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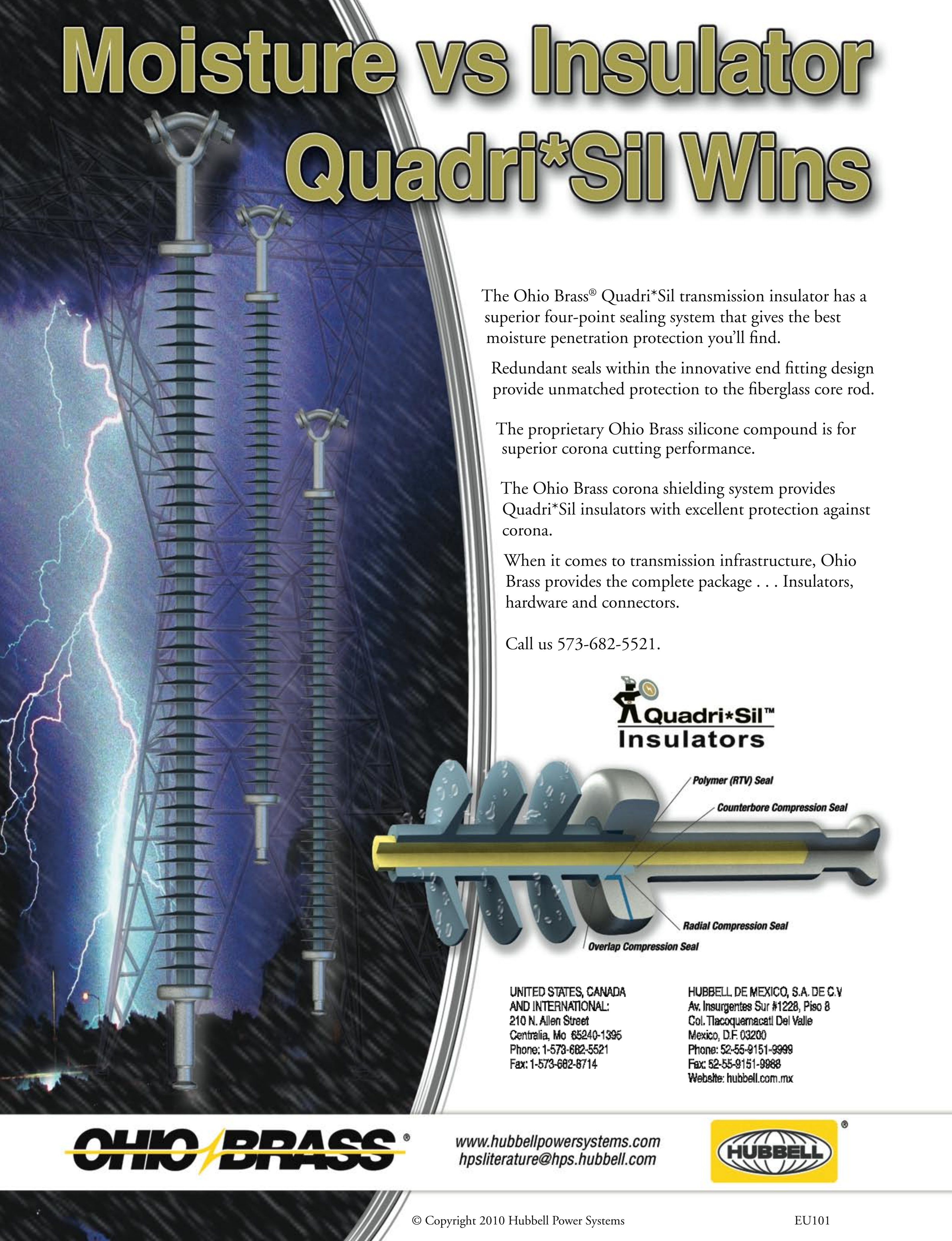

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WHY CALIBRATE TEST EQUIPMENT?

Fluke Corporation

You're serious about your electrical test instruments. You buy top brands, and you expect them to be accurate. You know some people send their digital instruments to a metrology lab for calibration, and you wonder why. After all, these are all electronic — there's no meter movement to go out of balance. What do those calibration folks do, anyhow — just change the battery?

These are valid concerns, especially since you can't use your instrument while it's out for calibration. But, let's consider some other valid concerns. For example, what if an event rendered your instrument less accurate, or maybe even unsafe? What if you are working with tight tolerances, and accurate measurement is key to proper operation of expensive processes or safety systems? What if you are trending data for maintenance purposes, and two meters used for the same measurement significantly disagree?

WHAT IS CALIBRATION?

Many people do a field comparison check of two meters, and call them "calibrated" if they give the same reading. This isn't calibration. It's simply a field check. It can show you if there's a problem, but it can't show you which meter is right. If both meters are out of calibration by the same amount and in the same direction, it won't show you anything. Nor will it show you any trending — you won't know your instrument is headed for an "out of cal" condition.

For an effective calibration, the calibration standard must be more accurate than the instrument under test. Most of us have a microwave oven or other appliance that displays the time in hours and minutes. Most of us live in places where we change the clocks at least twice a year, plus again after a power outage. When you set the time on that appliance, what do you use as your reference timepiece? Do you use a clock that displays seconds? You probably set the time on the "digitschallenged" appliance when the reference clock is at the "top" of a minute (e.g., zero seconds). A metrology lab follows the same philosophy. They see how closely your "whole minutes" track the correct number of seconds. And they do this at multiple points on the measurement scales.

Calibration typically requires a standard that has at least 10 times the accuracy of the instrument under test. Otherwise, you are calibrating within overlapping tolerances and the tolerances of your standard render an "in cal" instrument "out of cal" or vice-versa. Let's look at how that works.

Two instruments, A and B, measure 100V within 1%. At 480V, both are within tolerance. At 100V input, A reads 99.1V and B reads 100.9V. But if you use B as your standard, A will appear to be out of tolerance. However, if B is accurate to 0.1%, then the most B will read at 100V is 100.1V. Now if you compare A to B, A is in tolerance. You can also see that A is at the low end of the tolerance range. Modifying A to bring that reading up will presumably keep A from giving a false reading as it experiences normal drift between calibrations.

Calibration, in its purest sense, is the comparison of an instrument to a known standard. Proper calibration involves use of a NIST-traceable standard — one that has paperwork showing it compares correctly to a chain of standards going back to a master standard maintained by the National Institute of Standards and Technology.

In practice, calibration includes correction. Usually when you send an instrument for calibration, you authorize repair to bring the instrument back into calibration if it was "out of cal". You'll get a report showing how far out of calibration the instrument was before, and how far out it is after. In the minutes and seconds scenario, you'd find the calibration error required a correction to keep the device "dead on", but the error was well within the tolerances required for the measurements you made since the last calibration.

If the report shows gross calibration errors, you may need to go back to the work you did with that instrument and take new measurements until no errors are evident. You would start with the latest measurements and work your way toward the earliest ones. In nuclear safety-related work, you would have to redo all the measurements made since the previous calibration.

CAUSES OF CALIBRATION PROBLEMS

What knocks a digital instrument "out of cal"? First, the major components of test instruments (e.g., voltage references, input dividers, current shunts) can simply shift over time. This shifting is minor and usually harmless if you keep a good calibration schedule, and this shifting is typically what calibration finds and corrects.

But, suppose you drop a current clamp — hard. How do you know that clamp will accurately measure, now? You don't. It may well have gross calibration errors. Similarly, exposing a DMM to an overload can throw it off. Some people think this has little effect, because the inputs are fused or breaker-protected. But, those protection devices may not trip on a transient. Also, a large enough voltage input can jump across the input protection device entirely. This is far less likely with higher quality DMMs, which is one reason they are more cost-effective than the less expensive imports.

CALIBRATION FREQUENCY

The question isn't whether to calibrate — we can see that's a given. The question is when to calibrate. There is no "one size fits all" answer. Consider these calibration frequencies:

- Manufacturer-recommended calibration interval. Manufacturers' specifications will indicate how often to calibrate their tools, but critical measurements may require different intervals.

- Before a major critical measuring project. Suppose you are taking a plant down for testing that requires highly accurate measurements. Decide which instruments you will use for that testing. Send them out for calibration, then “lock them down” in storage so they are unused before that test.
- After a major critical measuring project. If you reserved calibrated test instruments for a particular testing operation, send that same equipment for calibration after the testing. When the calibration results come back, you will know whether you can consider that testing complete and reliable.
- After an event. If your instrument took a hit — something knocked out the internal overload or the unit absorbed a particularly sharp impact — send it out for calibration and have the safety integrity checked, as well.
- Per requirements. Some measurement jobs require calibrated, certified test equipment — regardless of the project size. Note that this requirement may not be explicitly stated but simply expected — review the specs before the test.
- Monthly, quarterly, or semiannually. If you do mostly critical measurements and do them often, a shorter time span between calibrations means less chance of questionable test results.
- Annually. If you do a mix of critical and non-critical measurements, annual calibration tends to strike the right balance between prudence and cost.
- Biannually. If you seldom do critical measurements and don’t expose your meter to an event, calibration at long frequencies can be cost-effective.
- Never. If your work requires just gross voltage checks (e.g., “Yep, that’s 480V”), calibration seems like overkill. But what if your instrument is exposed to an event? Calibration allows you to use the instrument with confidence.

IMPEDANCE/RETURN LOSS: THE BASICS

Paul Vanderlaan, Product Development Engineer

There is a new requirement making waves in the telecommunications industry. Return loss (RL) is being specified in the newly ratified TIA/EIA TSB-95 Additional requirements for category 5 cabling and the proposed Category 5e and Category 6 documents. These specifications have brought a new awareness to the industry of an electrical parameter Belden has been promoting for a number of years. This article will give a brief explanation of this new specification, why it is important, and what things may adversely affect the performance of the RL in your network.

RETURN LOSS

Return Loss is one of many parameters regulated by the requirements established for Category 5e and 6 cables. It is a measure of the reflected energy from a transmitted signal. It is commonly expressed in positive dBs. The larger the value, the less energy that is reflected. The following figure illustrates return loss and its effect upon the original signal. In the top portion, the signal is injected upon the pair. As the signal travels down the pair, portions of the signal are reflected back to the transmitter. These reflections are caused by impedance discontinuities in the channel.

These discontinuities may be due to several things such as connectors, improper installation or handling or improper manufacture. Any energy that is reflected, reduces the power of the transmitted signal.

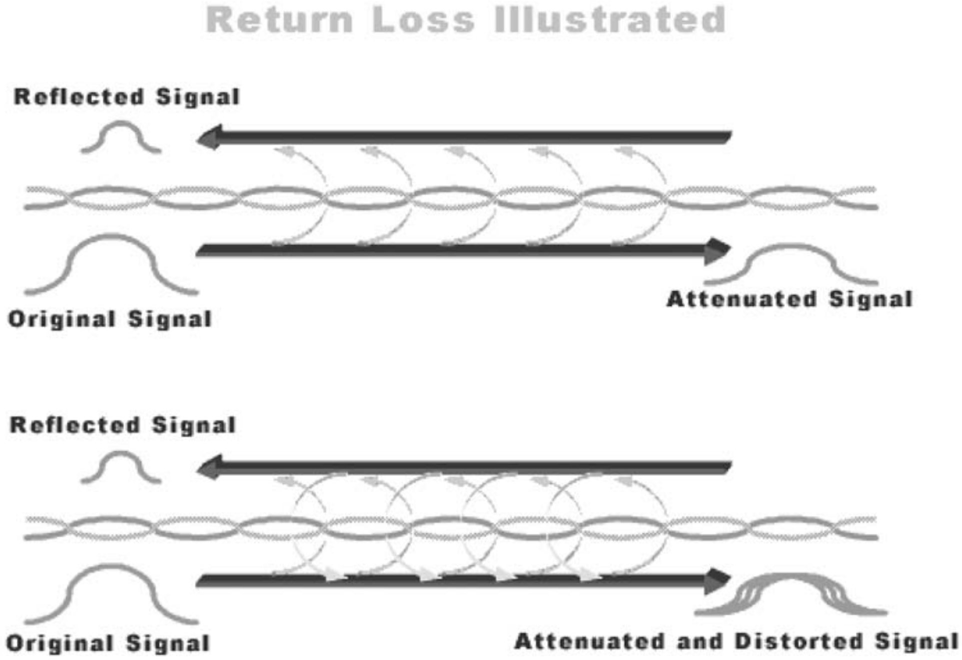


Figure 1

The lower half of Figure 1 shows the effects when the echo is reflected back to the right. The reflected echo combines with incoming data, effectively smearing the signal and making it harder for the receiver to resolve the signal. A simple analogy for RL would be talking into a large long pipe or tunnel. When one calls out down the tunnel, the caller can hear his or her own voice echoing back while the person at the other end hears a smear of multiple echoes along with the original voice. This echo distortion is similar to the effects of RL upon the transmitted signal.

Return loss can be calculated using the following equation:

$$RL = 20\log\left|(Zi - 100\Omega)/(Zi + 100\Omega)\right|$$

Zi = input impedance of the cable at a given frequency

In a lab environment, the value of a measured RL value is a negative number. However, in an attempt to avoid confusion, the standards refer to all measured values in a positive format. For comparison to a specification, this conversion is accomplished by placing a negative sign in front of the equation.

$$RL = -20\log\left|(Zi - 100\Omega)/(Zi + 100\Omega)\right|$$

It is understood in the industry that the specifications in the standards may be converted into a negative format in the same manner. For simplicity, all the charts presented here will be in a negative format and all comparisons will be made to a converted standard.

WHY IS IT IMPORTANT NOW?

In 10BaseT systems, two pairs are used for the transmission of data. Figure 2 represents a simple model of this system. Transmitters are indicated by the gray triangles pointing into the pair while receivers are pointed in the opposite direction. Looking at one end of the cable, one pair transmits while another pair receives data from the opposite end. In this system, the transmitter only sends data and is not listening for data from the other end. The reflected energy in this system does not affect the transmitter. Rather, it slightly attenuates and distorts the signal as it travels down the length of the channel to the receiver at the far end.

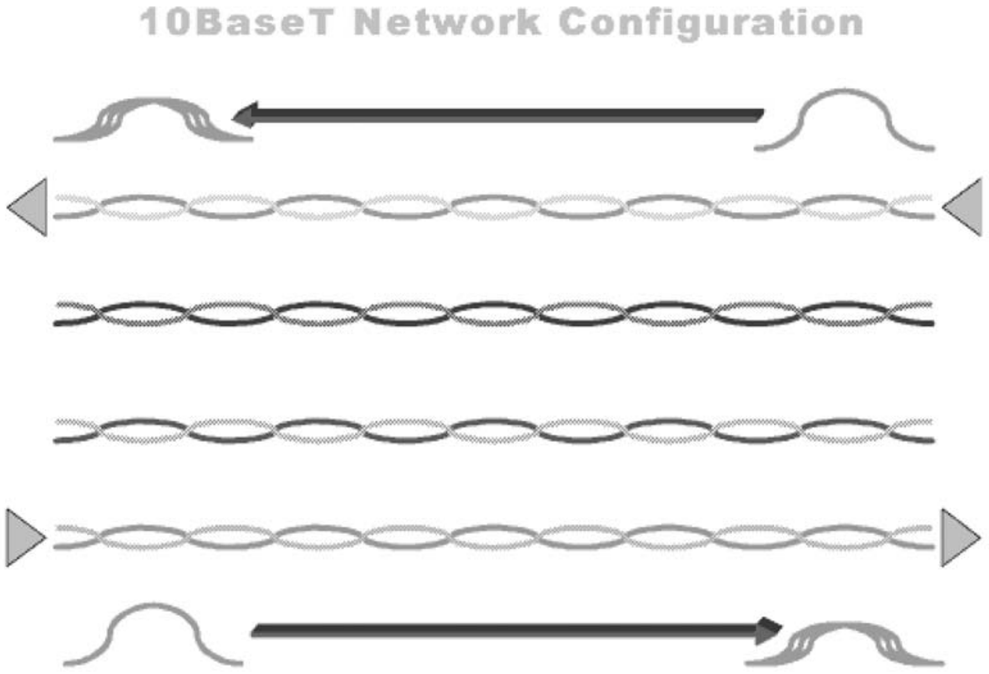


Figure 2

With newer systems such as 1000BaseT, the pairs at each end of the cable are now required to simultaneously transmit and receive data. This means that, as the transmitter is sending data, it is listening for data from the other end on the same pair. This would be similar to someone yelling down that tunnel while listening for the other person who is yelling at the same time. Any words arriving from the other person would suffer from the echo distortion. However, the echoes of the first person's voice are bouncing back at the same time as the distorted voice arriving from the other end. In a network, as the signal is sent from the near end, a portion is reflected back at the transmitter. This reflection mixes with incoming distorted data from the far end. This can make the interpretation of the transmitted data much more difficult.

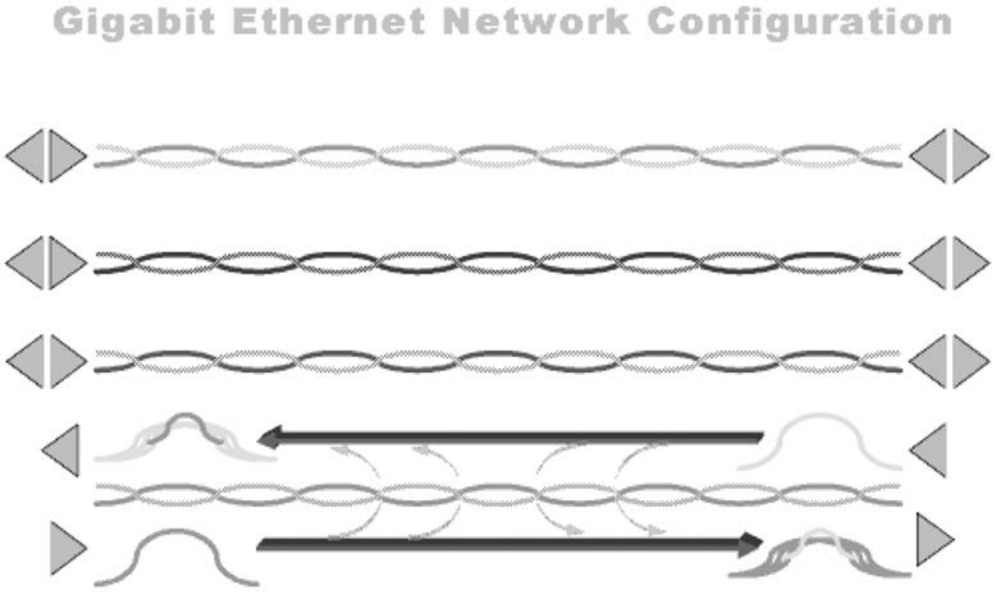


Figure 3

In a network, as the signal is sent from the near end, a portion is reflected back at the transmitter. This reflection mixes with incoming distorted data from the far end making the interpretation of the transmitted data much more difficult.

WHAT AFFECTS RETURN LOSS?

Return loss is generated through variations in the impedance of the channel. These variations can take the form of connectors with high or low impedance values. The average input impedance of the patch cables may be significantly different from the horizontal cable's average.

Additionally, the cables may have large impedance variations at specific points due to cable design instability. This instability can be attributed to the construction of the pairs and singles and may be aggravated by various handling and installation practices.

In a simplified model, the channel is a highway for data transmission. Changes in impedance can be viewed as bumps and potholes which may, depending on their severity, slow or stop the traffic flow of data. The RL is a measurement of how many "cars" are turned back due to the bumps and potholes versus how many actually made it to the end of the road. In short, RL can be interpreted as smoothness or uniformity measurement method for your cable or channel.

CONNECTOR RETURN LOSS

Connectors are a weak link in the channel's performance. Specifically, the split pair in the RJ-45 type connector is the major culprit. The physical separation of the conductors degrades the RL performance by disturbing the pair geometry. This separation of the pair generates an impedance discontinuity, causing signal reflections. Additionally, the near-end crosstalk (NEXT) compensation that some manufacturers performed on their older connectors aggravated the RL performance of the split pair. However, large improvements have been made to the new versions of connectors and this is becoming less of an issue making the cable performance more critical.

CABLE RETURN LOSS PARAMETERS

Cable return loss is regulated through two primary impedance parameters: the average input impedance and periodic impedance discontinuities. Each of these two parameters has several factors that affect their performance.

AVERAGE INPUT IMPEDANCE VS. RETURN LOSS

The unshielded twisted pair (UTP) systems regulated by the ANSI/TIA/EIA -568-A document are 100 ohm systems. When the average input impedance of a cable is different from 100 ohms, the RL performance will decrease. The primary determining factor in the cable's average input impedance is the conductor-to-conductor spacing, however, such things as jacket tightness or shields can also play a large role. Sometimes, the jacket is utilized to ensure core integrity. If excessive amounts of jacket are removed, this may have a significant effect upon the average input impedance by raising the average input impedance for the exposed segment of core. Additionally, the cable can be stretched or crushed during the pulling process.

Typical impedance and RL charts of a Belden bonded pair cable are depicted here.

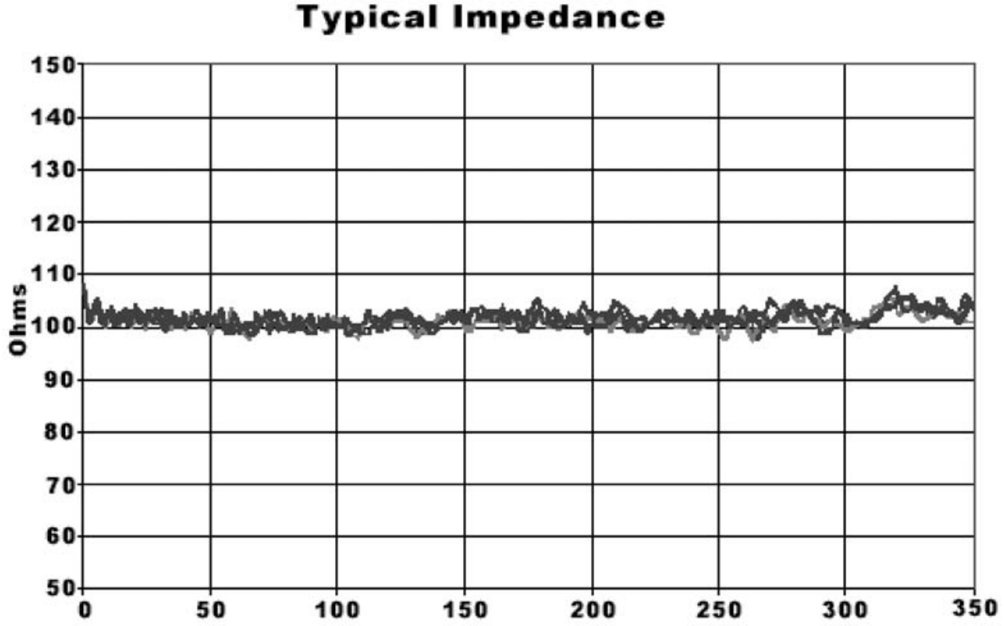


Figure 4

Notice that the impedance is very close to 100 ohms and the RL exhibits excellent performance with significant margin to the proposed Category 5e RL specification. The average input impedance for each pair is between 101.0 and 101.8 ohms and the standard deviation varies from a low of 1.4 ohms on one pair to a high of 1.6 ohms on the worst pair.

The following graphs indicate the importance of designing the cable to be as close to 100 ohms as possible. For illustrative purposes, the original impedance trace has been offset by a positive 7 ohms.

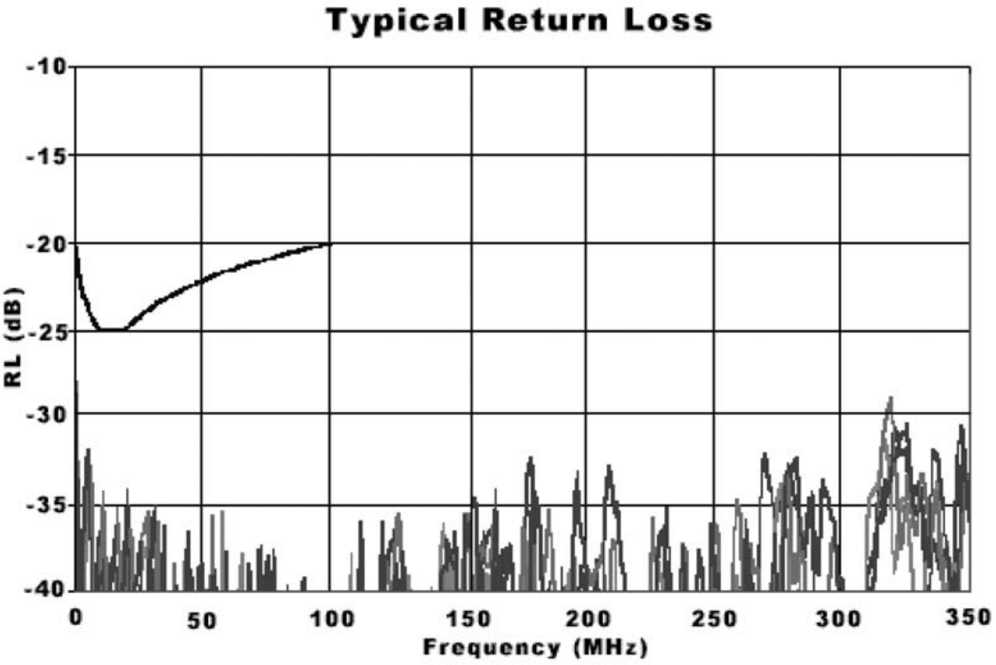


Figure 5

As indicated by the above charts, the RL performance has been significantly degraded with the positive impedance offset. There is almost no margin left for connectors, cable instability, or installation practices. This illustrates the importance of designing a cable to be as close to 100 ohms as possible.

PERIODIC IMPEDANCE DISCONTINUITIES

Periodic impedance discontinuities are the second major contributors to the RL performance of a cable. These discontinuities are a strong indicator as to the quality of the cable. These discontinuities can be generated by a number of things. Inside the cable, such things as singles diameter and conductor to conductor spacing are critical. The following Figures 8 and 9 represent a competitor's category 5e impedance and RL performance respectively. The average input impedance is between 103 and 105 ohms and the standard deviation varies from a low of 4.6 ohms on one pair to a high of 10.7 ohms on the worst pair. This is a strong indication that the pairs in this cable are not uniform and only provide marginal to failing performance, with no allowance for further installation effects.

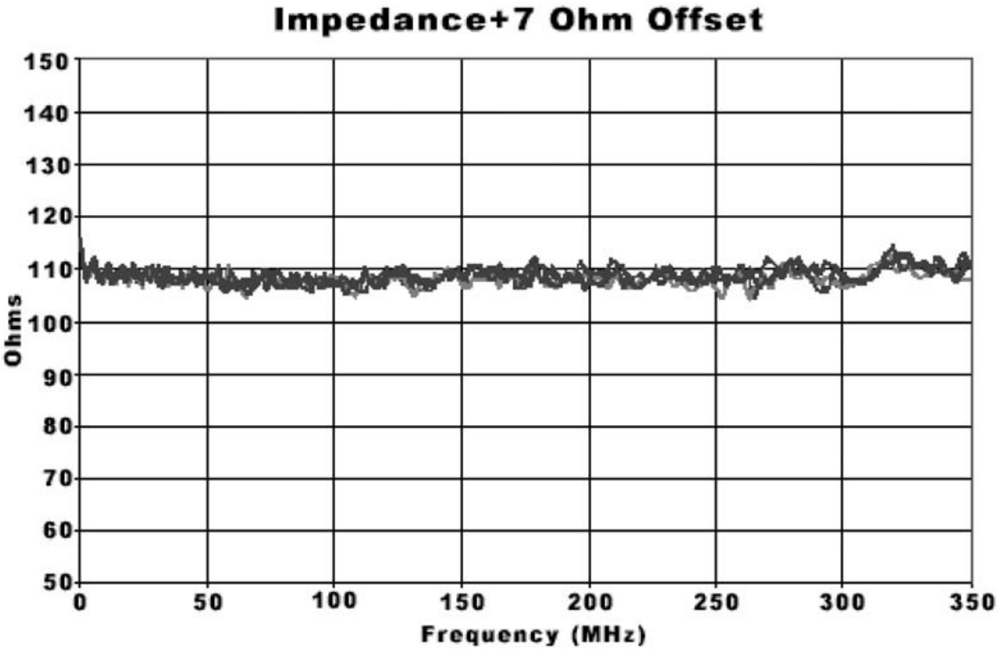


Figure 6

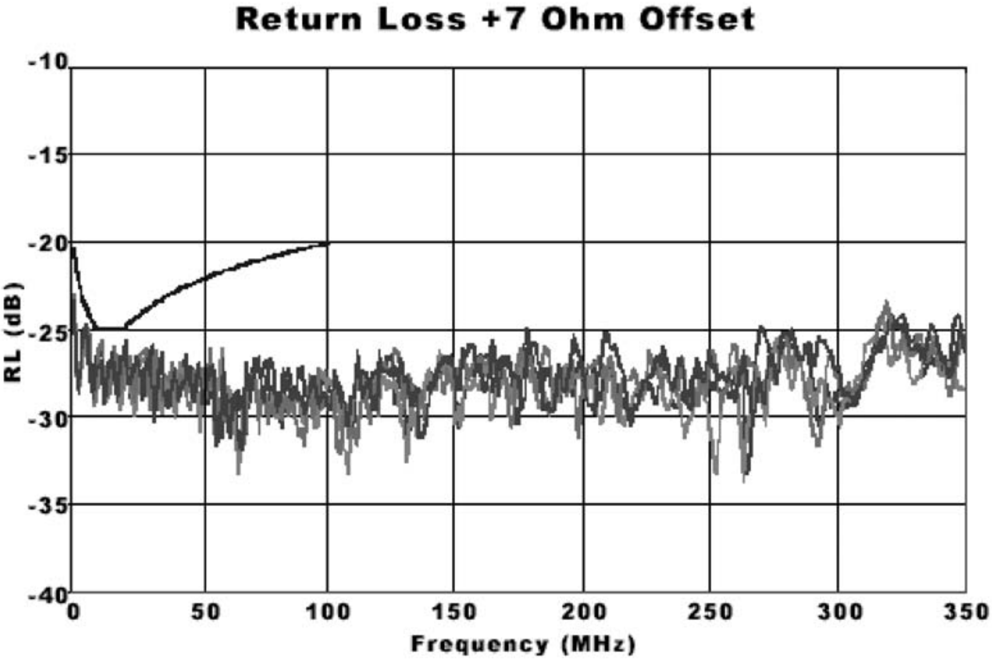


Figure 7

INSTALLATION EFFECTS

The final, and perhaps least understood, effect upon cable RL performance is the installation procedure. This involves a multitude of issues such as patch cable instability, package payoff, pair untwist, jacket removal, cable bundling, bend radius, and service loops. Some hand-held test manufacturers brought to the TIA committee's attention the fact that most of the patch cables on the market were suffering from very unstable RL. It was determined that the patch cable's RL performance would vary widely with minor changes in position. Cable packages that impart a twist or knots into the cable could be adversely affecting the cable's RL.

Pair untwist has always been critical for NEXT performance. Add RL into the equation and it may be time to re-evaluate the neatness of your wiring closet. Bundling, service loops and bend radii once thought ok for Category 5 cabling now have serious implications to the end user.

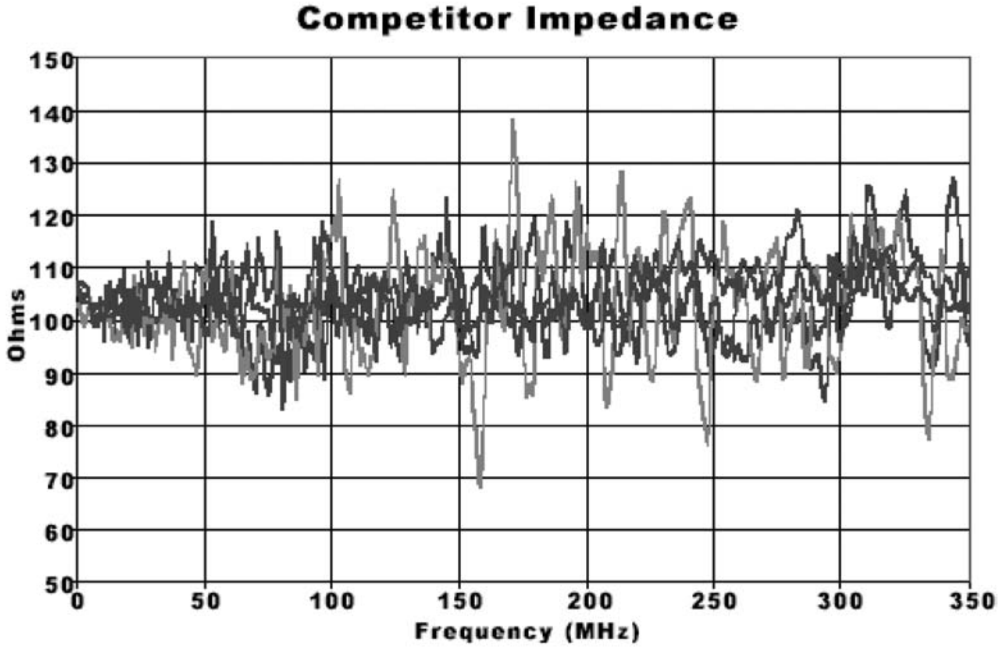


Figure 8

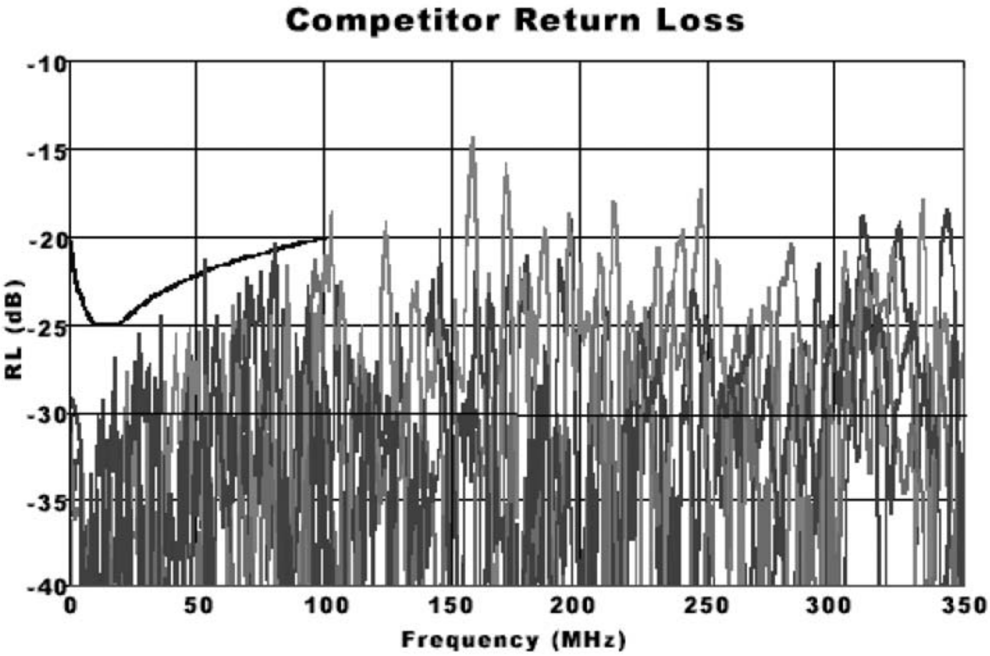


Figure 9

PERFORMANCE AND OPERATIONAL CHARACTERISTICS OF AN ADVANCED POWER SYSTEM

By Edward R. Furlong and William Wiltsch, GE Digital Energy, General Electric Company

INTRODUCTION

For many years, GE has been providing equipment, services, and engineering support to mission critical facilities such as data centers, semiconductor manufacturing plants, credit card processing centers, and more recently, web hosting facilities. In many instances, the construction timetable and the commissioning of these facilities were largely constrained by the installation and coordination of the electrical system.

GE has developed the Advanced Power System (APS), shown in Figure 1, to alleviate this constraint and improve both the reliability and serviceability of the electrical power infrastructure for these customers.

The design and component specifications were scrutinized by data center experts with hundreds of years of combined experience observing common failure modes in the industry. The APS can be used as a stand-alone unit, as part of a multi-unit system, or even combined with the existing electrical infrastructure for increased power or improved reliability.

Figure 1 The APS1500 with generating module (left) and conditioning module (right).

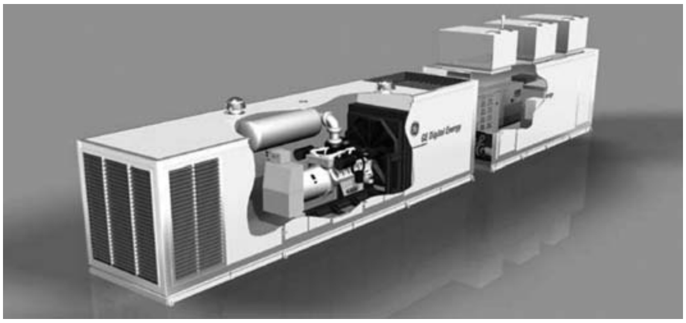


Table 1Summary specifications of the APS1500

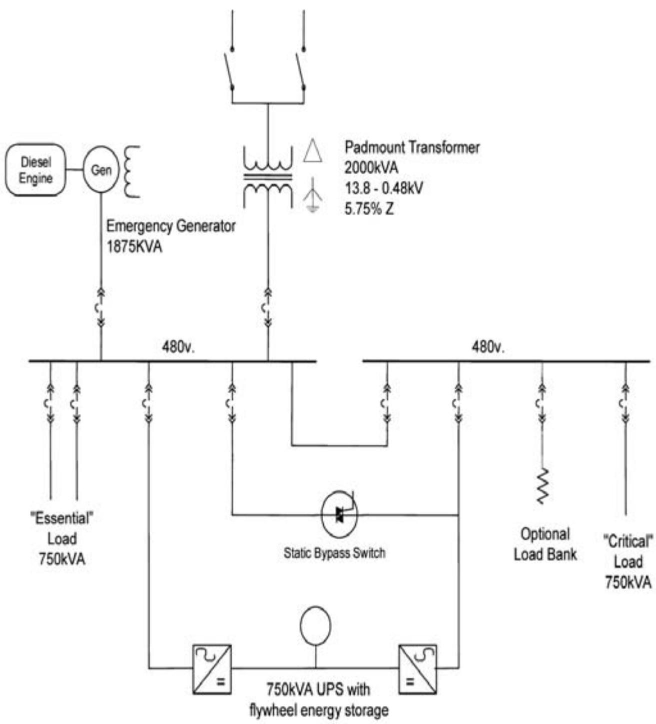
Attribute	Value
System Voltage	480VAC, 60 Hz 3 phase, 4 wire, solidly grounded wye 100kAIC max.
Max Critical Loads	750 kVA
Max Essential Loads	627 kW
Static Bypass Switch	Internal to UPS
Outdoor Ambient	-20 to 104 °F
Wind Rating	130 mph
Cond. Module size	29.9L x 12.3H x 10.9W ft
weight	62,000 lbs
Gen. Module size	47.8L x 12.3H x 10.9W ft
weight	86,000 lbs
noise	85 dBa

There are two parts to the APS: 1) the conditioning module, which houses the switchboard, the UPS, the flywheel energy storage system and the control system, and 2) the generating module, which houses the backup generator and the sound attenuation equipment. Summary specifications are listed in Table 1. The 1500 kW fast-start diesel is sized to provide backup power to not only 750 kVA of conditioned power (the "critical" loads), but also an equivalent amount of power for the air conditioning and handling motors required to keep the building cool (the "essential" loads).

A simplified one-line of the APS1500 is shown in Figure 2. The incoming utility is directed to a pad-mounted transformer to produce three-phase, 480V power for input to the APS. The available paths are to the two essential load breakers, the UPS, the static switch bypass, and the manual bypass. There are additional breakers for auxiliary loads within the APS.

Besides the critical load output breaker, there is an additional breaker on the critical load output bus for an optional load bank to test the UPS during service. A Kirk key sequence aids in protecting the critical loads when the UPS must be bypassed for maintenance on either the UPS or the energy storage system.

Figure 2 Simplified one-line diagram of the APS1500



INSTRUMENTATION AND APPROACH

The prototype unit was connected and instrumented as shown in Figure 3. Two hundred feet of 4/00 cable, eight strands per phase, was laid over ground between the generating module and the conditioning module. A similar amount was laid between the rental genset and the conditioning module, simulating a utility feed. In addition to the power cables, two multi-strand shielded cables were also used to connect the modules, one for the genius I/O, and the other for the Digital Synchronizer and Load Control (DSLC). For permanent installations, it is recommended to use either 500mcm or 750mcm cable instead of the 4/00 cable used here.

An abbreviated list of the sensed parameters is included in Table 2.

The switchboard has potential transformers (PTs) and current transformers (CTs) on the incoming utility, the backup generator, the critical bus and the essential bus breakers. The critical bus output is also monitored by a power quality meter. The incoming utility feed is monitored by a microversatrip (MVT) in the circuit breaker as well as an SR750 protective relay. The backup generator, in turn, is monitored by an MVT and an SR489 relay. The DSLC, the SyncCheck relay, the SR750 and SR489 are utility grade relays and will protect both the utility and the backup generator when or if the two are paralleled.

APS PERFORMANCE EVALUATION

The prototype and first production units underwent extensive performance evaluation testing. The overall goals of this testing were to:

- Validate stability, dynamic and reliability analyses;
- Ensure CBEMA-compliant output to various scenarios with poor input power quality;
- Verify the proper response to system faults and potential failure modes.

This testing and quality assurance began even before the completion of the first unit. All of the components and subassemblies were tested prior to installation at the factory. For example, the breakers and switchboard were tested by primary current injection, repeated cycling, PT and CT calibration, and continuity of the secondary interconnections.

Table 2. Sensed parameters. A partial list of the parameters monitored by the RM&D system. The data sets for Figures 4-8 were acquired on a Yokogawa DL316 oscilloscope

Component	Parameter	Instrument
Utility Feed	Phase-Phase Voltage	SR750, MVT
	Three Phase Current	SR750, MVT
	Power	SR750, MVT
Generator	Phase-Phase Voltage	SR489, MVT
	Three Phase Current	SR489, MVT
	Power	SR489, MVT
UPS Output	Phase-Phase Voltage	PQM, MVT
	Three Phase Current	PQM, MVT
	Power	PQM, MVT
	CBEMA Compliance	RPM
	Harmonic Content	RPM
Flywheel	Speed	Tachometer
	DC Link Voltage	Multimeter

Care was taken to avoid wear on the mechanical components during the testing, while still ensuring the integrity of the design.

The UPS/flywheel subsystem was tested for communications, alarms, interlocks, stability, ridethrough, walk-in time, transformer in-rush, recharge time, breaker and bypass functionality, and response to both short and long outages. The other subsystems were tested as well, including the control panel, the

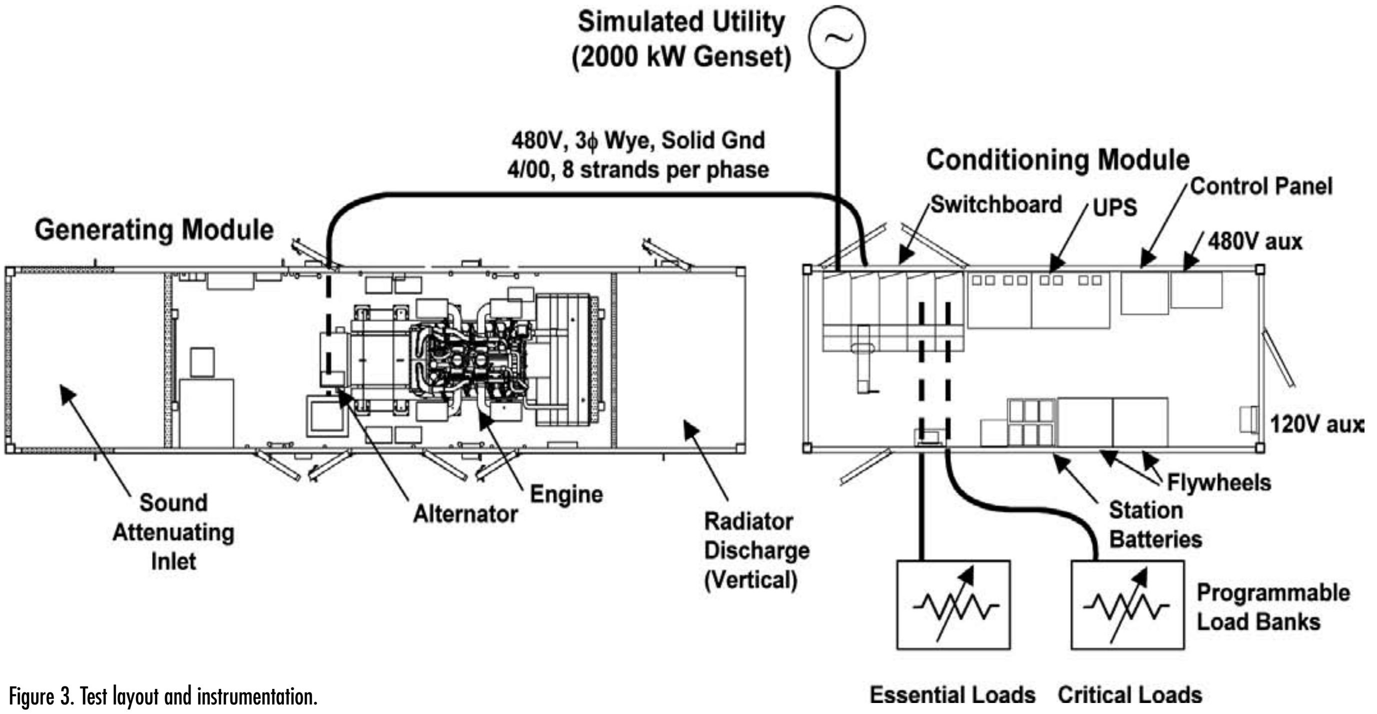


Figure 3. Test layout and instrumentation.

station batteries, the HVAC units and the diesel genset

The fault detection and control software was evaluated using simulated I/O configured from the design specifications. Automated testing software was then designed to verify continuity and functionality for component interconnections during the final I/O check at the factory.

POWER OUTAGE RESPONSE

Of paramount importance to a mission critical facility is the response to a power outage. These are the most disruptive of all power quality events, and generally occur between one and ten times per year, depending on the location.

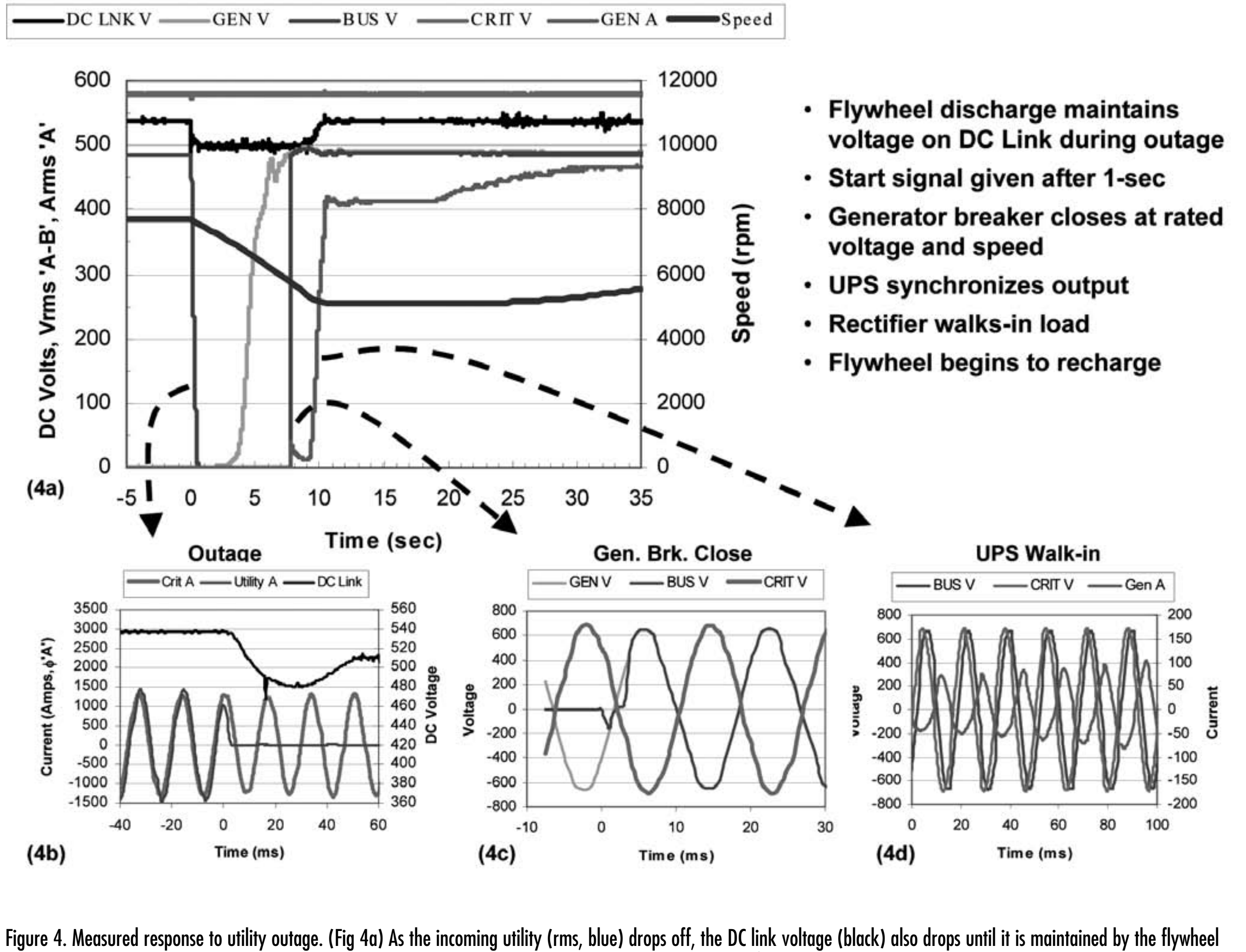
The response of the APS to an extended outage is shown in Figure 4. At time t=0, the incoming utility feed is cut. As the bus voltage falls to zero, the voltage of the DC link also drops. When the DC link voltage has dropped below 520V, the flywheels begin to discharge. After a few milliseconds, the voltage is stabilized at 510V, as shown in Figure 4b. Note that the critical-loads output (shown in red) is unaffected by the disruption in the input power. This isolation is the hallmark of a true double conversion UPS.

After a 1-sec delay, the start signal is given to the fast-start generator. When it reaches rated speed and voltage, the utility and essential-loads breakers open, and the generator breaker closes, restoring voltage to the bus. The curves (APS bus) then overlap with the curves (generator bus) in Figures 4a and 4c. Note that the incoming bus voltage is not synchronized with the critical-loads output voltage. This is because the generator phase is random relative to the dead utility bus. The UPS inverter will synchronize to the rectifier input in order to enable the static bypass.

With the voltage restored and synchronized, the UPS rectifier begins the walk-in phase, shown in Figure 4d. As the rectifier current increases, the power drawn from the flywheels decreases. When the rectifier can fully supply the power (approximately 1.7 sec), the DC link voltage returns to 540V. As the system stabilizes, the flywheels begin to recharge (notice the increase in current in Figure 4a at time t=20sec).

FLYWHEEL ENERGY STORAGE SYSTEM

As described in the previous section, stored energy from the flywheels is tapped to supply power to the critical loads when-



- Flywheel discharge maintains voltage on DC Link during outage
- Start signal given after 1-sec
- Generator breaker closes at rated voltage and speed
- UPS synchronizes output
- Rectifier walks-in load
- Flywheel begins to recharge

Figure 4. Measured response to utility outage. (Fig 4a) As the incoming utility (rms, blue) drops off, the DC link voltage (black) also drops until it is maintained by the flywheel (dk red). When the backup generator hits rated speed and voltage, the bus voltage is restored, the UPS rectifier begins the walk-in phase, and the DC link voltage increases. Note the increase in the generator current (dk.gn.Arms/2) as the flywheels begin to recharge (t=20 sec). Input and output waveforms during the utility dropout (Fig 4b), the generator breaker closing (Fig 4c), and the UPS walk-in (Fig 4d). In all the figures, note the stability of the critical bus output (red curves), and thus the degree of isolation from the grid provided by the double conversion UPS chosen for the Advanced Power System.

ever there is a dip in the DC link voltage. When a battery is used for energy storage, the duration that power can be supplied is a function of the amount of stored chemical potential.

For the flywheel system, this duration, t_f, is a function of the moment of inertia of the flywheel ($I=0.5mr^2$, m=mass, r=radius), its initial speed and minimum speed (w_i, w_m), the amount of critical load, P_c, and the overall efficiency (h), as:

$$t_f = \eta \; I\,(\omega_i^2 - w_m^2) / P_c.$$

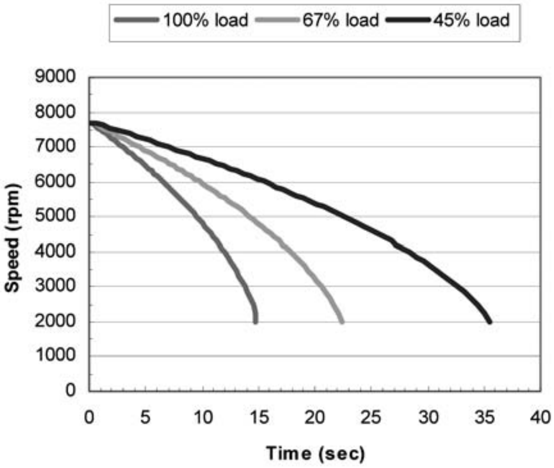


Figure 5. Variation of flywheel speed as a function of time for three levels of applied load. Under normal utility operation, the flywheel is maintained at 7700 rpm. During ride through, the stored energy is transferred to the DC link of the UPS and the flywheel speed drops parabolically. When the lower limit of 2000 rpm is reached, the output is suspended.

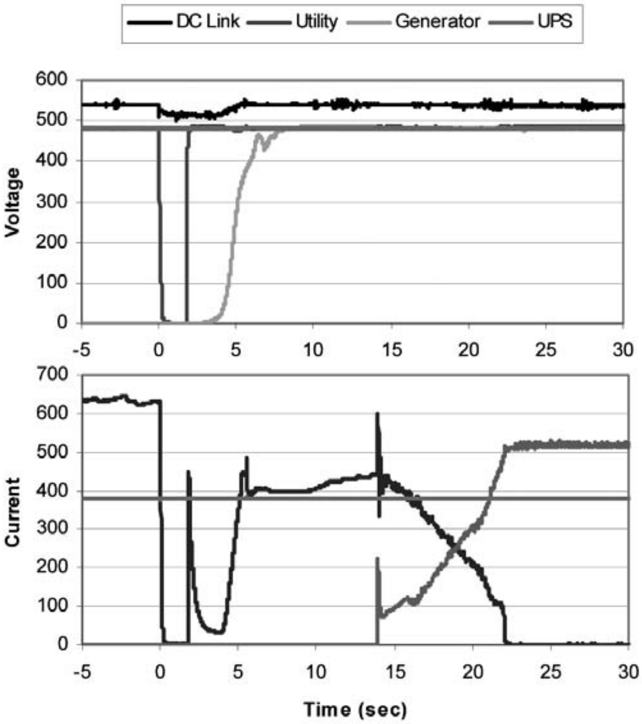


Figure 6. Simulated 3-sec switch recloser. When power is lost for more than 1 sec, the backup generator is started as a precautionary measure. The returning utility still provides power to the bus until the generator comes on line. A closed transition is used to softly transfer the load to the backup generator.

The duration of stored power (stored energy) was computed from the equation above and verified experimentally. The measured speed of the flywheels as a function of time is shown in Figure 5 for three different power output levels.

There are two features of this figure that are of particular importance. The first is the predictability of the performance. The trajectories are smooth and parabolic, as expected. This is very different than the response of battery systems, especially after several complete discharges. Second, the duration (or ride-through time) is far more linear with load than a typical battery system.

For system configurations that are highly redundant (such as system plus system, or N+N), the ride through can more than double. This extra time can be added to the generator start signal delay which, in turn, allows more time for the utility to return and minimizes nuisance starts of the backup system.

OPEN AND CLOSED TRANSITIONS TO THE UTILITY

Whenever there is an outage longer than the preset delay or a series of outages that deplete the stored energy in the flywheel below its preset limit, the generator will be started and the load will be transferred to it as a precautionary measure.

This is illustrated in Figure 6 during the response to a 3-sec switch recloser. As before, the flywheel discharge maintains the voltage on the DC link during the brief outage, and after a 1-sec delay, the start signal is given to the generator. Before the diesel genset has reached rated speed and voltage, however, the utility voltage has returned. The inrush current on the input transformer of the UPS rectifier is clearly evident on the lower frame of the figure.

After the UPS senses the return of the input power, there again is a delay while the phase of the UPS output is synchronized to that of the UPS input.

The UPS rectifier then walks in the load and the DC link voltage returns to 540V.

During this time, the Digital Synchronization and Logic Controller (DSLC) is attempting to synchronize the generator speed and voltage to that of the utility. When the speed, phase angle displacement, and voltage are within the specified limits, the DSLC signals for the generator breaker to close and then begins a soft transfer of the load (at t=14 sec).

When the load transfer is complete, the utility breaker is opened (t=22 sec).

Soft transfers, like the one shown in Figure 6, are the preferred method to transfer to and from the utility. However, when soft transfers are not allowed by the local utility, the two remaining options are: 1) an open transition, similar to the forced outage shown in Fig 4, and 2) a momentary closed transition.

During a momentary transition, the utility and backup power source are paralleled for a few cycles, roughly 100 ms. The coordination between the breakers, relays and controls of the APS are clearly evident in a momentary transition, such as the transfer from generator to utility power illustrated in Figure 7.

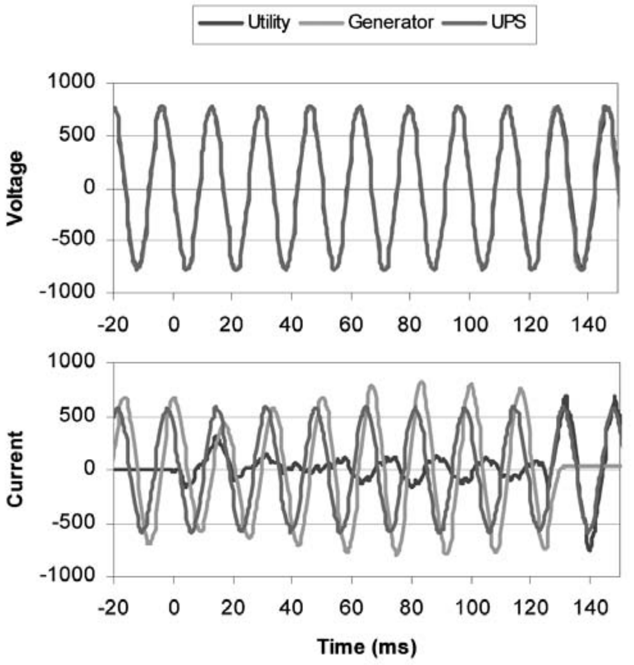


Figure 7. Momentary closed transition. In locations where soft transfers are not allowed by the local utility, a momentary transition can often be used instead. This is still preferred to an open transition as it maintains the essential loads.

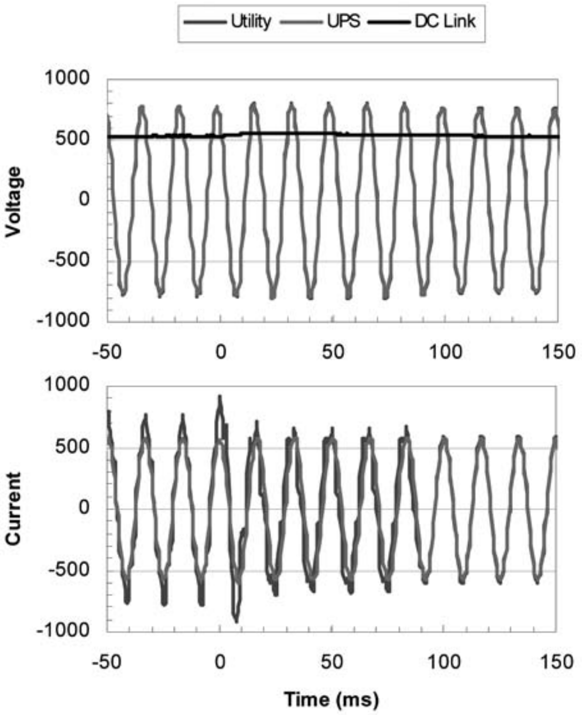


Figure 8. Transfer to bypass. When there is a problem with the UPS or a need for preventative maintenance, the UPS can be transferred to bypass using the built-in static switch. This enables seamless transfer of the critical load to either utility or backup generator power via the maintenance bypass circuit.

The DSLC synchronizes the backup generator to the utility. When synchronized, the utility breaker is closed, paralleling the two sources. After 100 ms, the generator breaker is opened, returning the system to utility power.

This type of transition has several advantages over the open transitions. During an open transition, the essential loads breakers must be opened to avoid inrush currents from the motor loads. Once the system and critical loads are stabilized, the essential loads are started sequentially. During a momentary transition, though, there is no interruption to either the critical or the essential loads. This dramatically reduces the impact of both routine and emergency maintenance. Furthermore, most customers are simply uncomfortable creating a forced outage, even though the system is designed to handle it. A momentary transition is often a good compromise.

UPS AND FLYWHEEL MAINTENANCE

While the components used in the APS are of the highest quality, there is still an occasional need for both planned and unplanned maintenance. In those instances, when the equipment needing service is either the UPS or the flywheel, it is imperative that the transfer to maintenance bypass occurs without dropping the load.

The transfer to bypass is illustrated in Figure 8. The first step is to fire the static switch (t=0). This transfers the load directly to the utility source. After a brief delay, the mechanical bypass is closed and the static switch is again opened. As is clearly evident in the figure, the critical load is unaffected by this transfer. With the UPS de-energized, the UPS or flywheels can be isolated to begin the required service, all without any disruption to the facility operations. When the maintenance is complete, the process is reversed, and the power is again conditioned and protected. A Kirk key sequence (a series of locks) has been installed on the breakers to ensure proper sequencing during this procedure. This seamless transfer to bypass has been shown to improve the reliability of stand-alone UPS systems by nearly a factor of 10.

FAILURE MODES AND EFFECTS ANALYSIS AND TESTING

The reliability of critical power systems is strongly affected by their ability to withstand single, or even multiple, component failures without dropping the critical load. This requires not only diligent system design, but also systematic and thorough testing during and after the construction.

All too often in our experience, a sound design which was misinterpreted during implementation resulted in a wrongly terminated wire or a missed line of code which ultimately caused an outage. Some of these events occurred years after commissioning because they involved second-tier failure modes that only materialize over time.

To minimize the chance of such an occurrence, detailed analysis must be performed to identify the probability of different failure paths. The analysis begins with FMEA or fault tree assessments, and culminates with detailed computer models that

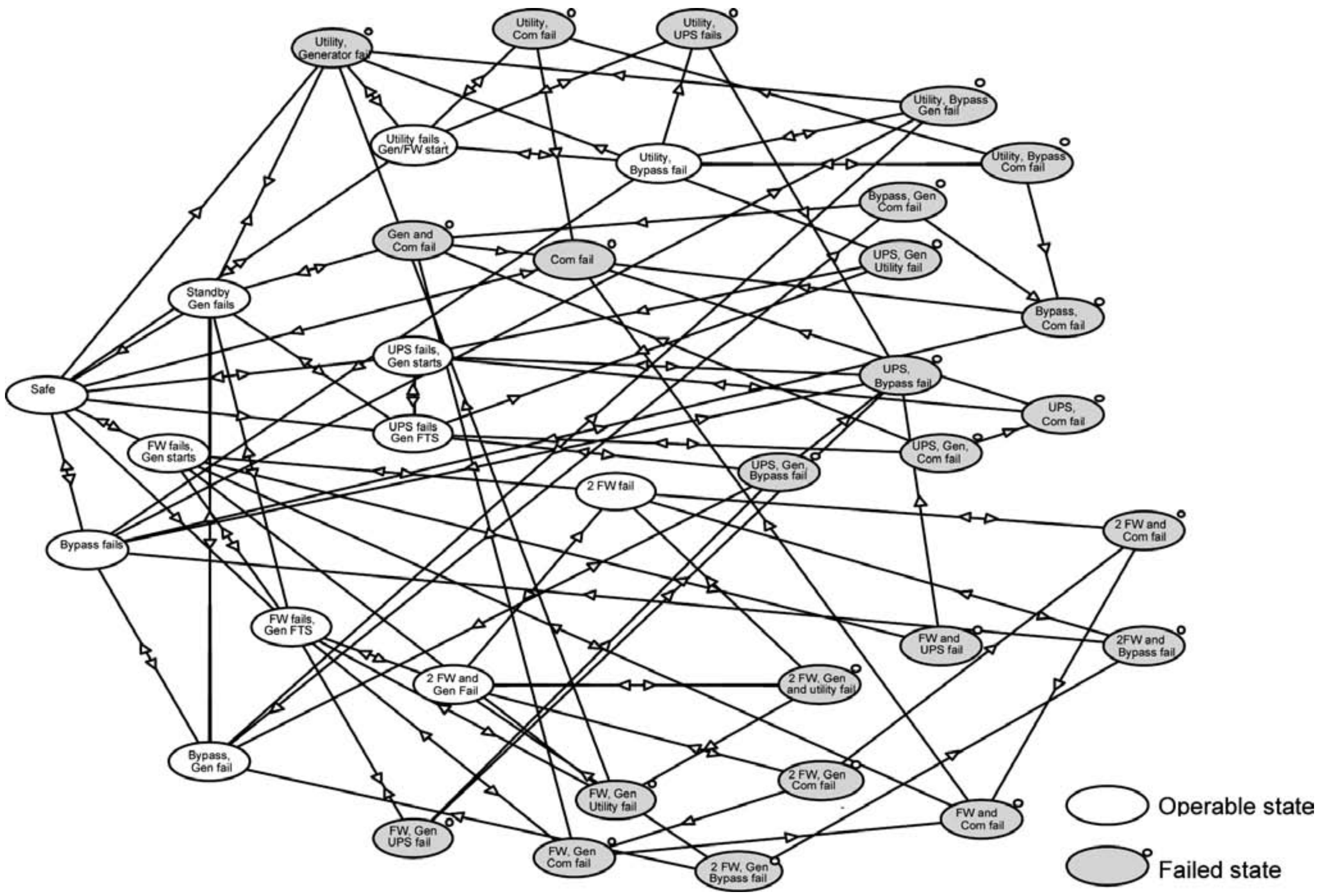


Figure 9. Top level Markov model for the APS. Advanced reliability tools such as Markov, Matlab, and modeling were used to isolate single points of failure and construct FMEA testing sequences.

can simulate a myriad of power quality events and the resultant impact of system architecture, component failures, and logistics delays on the overall reliability.

The analysis is then used to form a detailed test plan, which includes a detailed test and reporting procedure for each of the failure modes that had a meaningful impact on the overall system reliability.

A few of the major failure path items that the APS was proven to handle successfully include:

- Genset will start with jacket water heaters and room heaters disabled;
- Genset will start with only one starting motor;
- Only 2 (of 3) flywheels required to withstand voltage sag;
- No stability problems encountered with one phase unloaded (Input/Output load imbalance);
- APS internal temperature maintained with only 2 (of 3) HVAC units operating.

The extensive rigor in the design, testing, and service of the APS results in a mean time between failure (MTBF) that is nearly double that of currently available alternatives (47 years vs. 29 years).

Repeatable, high-quality factory assembly and test result in a reliable, scalable, and easy to install power system.

SUMMARY

The Advanced Power System (APS) was developed by GE Digital Energy as a means of improving the quality, reliability, and ease-of-use of the electrical infrastructure commonly used in mission critical facilities. The coordinated and robust operation of the APS is evident in its ability to maintain output compliant with CBEMA, ITIC and SEMI-F47 during power quality events and utility transfers, even with subsystems or components disabled and in alarm. These pre-engineered, prepackaged, and pre-tested systems offer a compact, cost-effective and scalable solution which is suitable for stand-alone, multi-unit, and facility upgrade applications.

ACKNOWLEDGEMENTS

The authors gratefully acknowledge the support and expertise of the GE Digital Energy staff along with Gary Kuhn, Tony Deig, Tom Reisinger, and Rich Thomas from GE Engineering and Automation Services, and the many committed supplier team members who assisted during the course of this testing.

LINE LEAKAGE TESTING: IS IT RIGHT FOR YOUR APPLICATION?

The Slaughter Company

INTRODUCTION

The Line Leakage test (LLT for short) is most often specified to be performed as a type test in a design or engineering laboratory or as a routine production line test on medical devices right before they ship. Not as commonly performed as a Dielectric Withstand or Ground Bond test in a production environment, LLT can cause some confusion for engineers and technicians alike.

However, technological advancements have begun to lessen the outward complexity of the test.

What used to be complicated set-ups and testing procedures has now been simplified with the use of multi-function testing instruments. For instance, all-in-one testing solutions such as our 6330 now come equipped with the components and relay switching networks to perform leakage tests in an automated sequence with little or no input from the test operator. This makes for safer and more efficient testing.

Electrical products including anything from appliances to handheld tools must be tested during the design and development phase in order to receive a safety agency listing. In these laboratory environments, the LLT is used to help ensure that the product's manufacturing processes and assembly practices are satisfactory. Along with other common tests such as the Hipot and Ground Bond tests, the Line Leakage test is used in this situation primarily as an indicator of design quality.

Some products, such as medical equipment, are designed with the intention of direct contact with a patient. Line Leakage tests should be performed on these products as a 100% routine production line test. Due to the sensitive nature of the applications for which this type of equipment is used, it is easy to see why rigorous testing must be performed as a routine test.

Whether the LLT is being performed as a type test or as a production test, the purpose of the test is the same: to determine if a product's insulation has the integrity to prevent any current from reaching the operator. When current does find its way through or across any part of a product's insulation system, it is known as leakage.

There are several methods manufacturers employ to prevent leakage, such as utilizing reinforced or double insulation systems and providing sufficient spacing between current-carrying conductors. Despite these measures, leakage current will be present in every product to some degree. Indeed, the electrical relationships between the very materials used in a product's construction are what account for a substantial portion of any resulting leakage. While the resistance of the insulation will account for some leakage, using an insulating material in between conductors creates a certain amount of distributed capacitance which helps to facilitate leakage to ground. This current will look to travel through a product's insulation system and return to ground by any means available, whether that is through a safety earth ground connection, or through an operator who is at ground potential.

For example, medical devices that run off of line power have components that are in direct contact with a patient. In this case a wall outlet, an almost unlimited power source, has a direct connection to a patient who could already be sick or frail. It is of vital importance in this scenario that the leakage current produced by the product be small enough so as not to be perceived by the individual to whom the device is connected. More importantly, the insulation of the device needs to have the integrity to prevent any current from reaching the patient.

A CLOSER LOOK AT THE LINE LEAKAGE TEST

The Dielectric Withstand (Hipot) test or Insulation Resistance (IR) test are common safety tests performed in both production line and lab environments. These tests do a good job of determining whether a product is manufactured correctly with good insulation, but they don't tell us how much leakage current could be flowing through a product while it is running. Furthermore, these tests cannot tell us how that leakage current might change under different conditions. There is no way to determine what might happen if the product is connected to a power source incorrectly, if the operator plugs the product into an outlet that is wired incorrectly, or if the neutral side of the line opens up. The Line Leakage test was developed as a way of determining how leakage current would act conditions such as these.

The Line Leakage test is actually a general term that is used to describe a series of tests. There are 4 different types of LLTs: Earth Leakage test, Enclosure Leakage test, Patient Leakage Current test, and Patient Auxiliary Current test (we will discuss each type of test later in the document). Each test is performed under nominal operating conditions as well as in a variety of fault conditions. These fault conditions provide us with valuable information about how a product's leakage current will behave if operated incorrectly.

Figure 1.0: Model 6330 6-in-1 Electrical Safety Tester (including LLT)

While the test setup may vary from test to test, the actual test methodology doesn't change. One-box solution testers such as the our 6330 come equipped with the components and relay switching networks to perform all Leakage tests in an automated sequence with little or no input from the test operator. The 6330 also has the capability to record leakage using Peak or RMS measurements, a feature beneficial for manufacturers who must comply with standards such as IEC 60990. (See Figure 1).

MEASURING DEVICES

Since the LLT is designed to measure the leakage current of a product while it is running, the way in which the current is measured is of vital importance. Therefore, Line Leakage tests incorporate measuring devices (MDs), which simulate the impedance of the human body. The placement of the measuring device is the factor that distinguishes one type of LLT from another. Measuring devices are specified by safety agencies depending on product classification and the standard to which the product is being tested. For the most part, MDs are resistive and capacitive networks designed to simulate the impedance of the human body in certain conditions. In most of today's testers, these measuring devices are incorporated in the circuitry of the tester.

During Line Leakage tests for example, MDs can be used to approximate full hand-to-hand or hand-to-foot contact. Figure 2.0 shows the network that should be used when testing to EN60601-1.

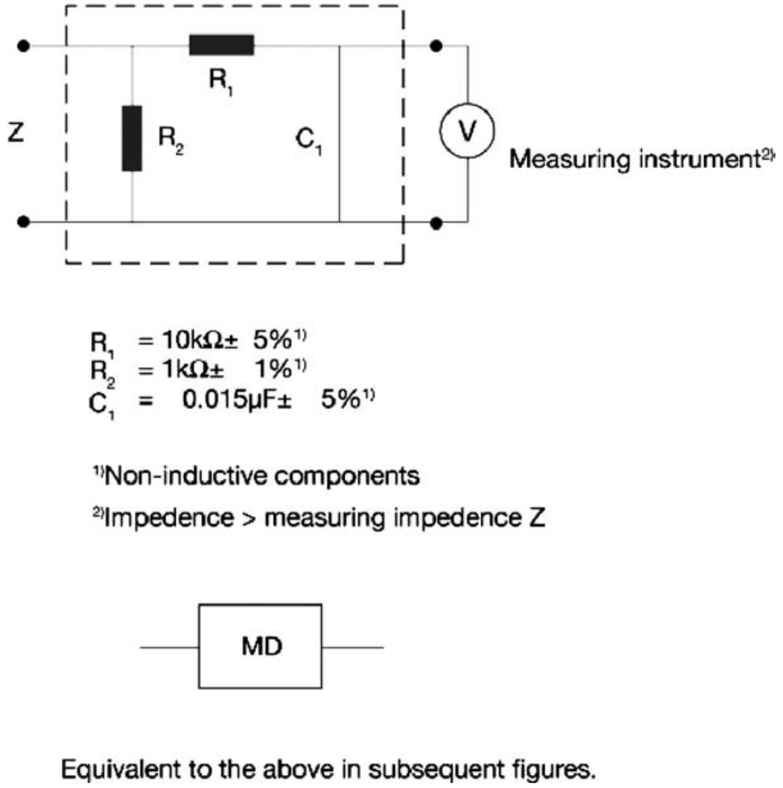

R1
Z
R2
C1
V
Measuring instrument2)
R1 = 10kΩ± 5%1)
R2 = 1kΩ± 1%1)
C1 = 0.015µF± 5%1)
1)Non-inductive components
2)Impedence > measuring impedence Z
MD
Equivalent to the above in subsequent figures.

Figure 2.0: MD Schematic for EN60601-1

Many safety agencies differ in their interpretation of how the test's MD should be configured. Regardless of where the MD is placed or how it is configured, the test should measure how much leakage current would flow through a person if they were to come into contact with the device under test (DUT). Below is an example of an internal switching network that may be found in a Line Leakage Tester.

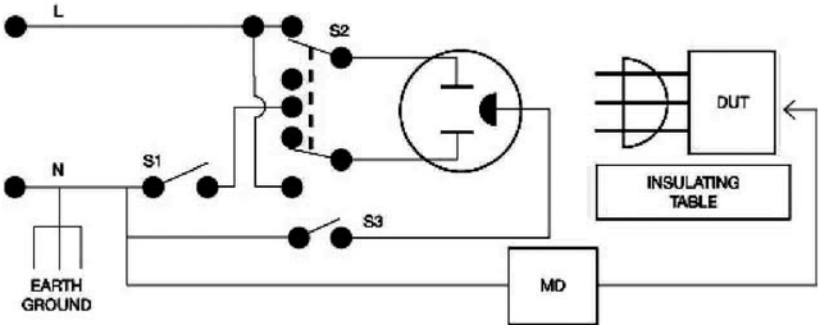


Figure 3.0: 6330 Internal Switching Network

In this internal switching network the MD can be any one of 8 built-in measuring devices as specified by safety agency standards. Relays S1, S2, and S3 are used to simulate the various fault conditions during testing. S1 corresponds to the open neutral condition, S2 to the reversed polarity condition, and S3 to the open ground condition.

FAULT CONDITIONS

The LLT is performed in both normal and single fault operating conditions. Measuring leakage current during fault conditions is important in order to determine if a product fails "safely", if it fails at all. A product that fails safely will not produce excessive leakage current even if one of the following combinations of fault conditions occurs. Table 1.0 on the following page shows the various combinations of relay closures that will simulate up to 8 total testing scenarios.

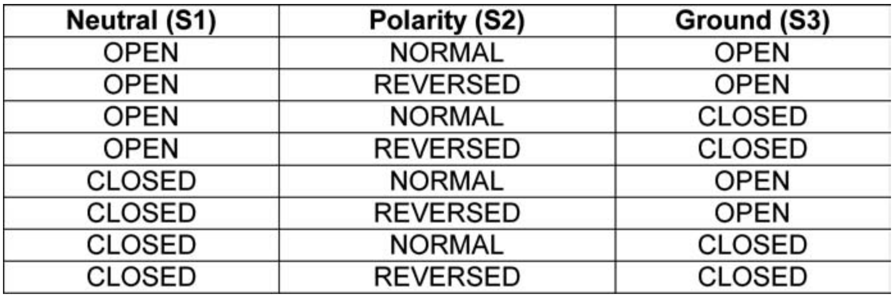
TEST SETUP AND PROCEDURE

EARTH LEAKAGE TEST

The Earth Leakage test places the MD from the earth ground pin of the DUT to the neutral side of the line (which is referenced to ground). In this configuration, power is applied to the DUT at 110% of the nominal voltage level using an isolation transformer. The MD is used to measure the amount of leakage current flowing from the mains-input line and returning to ground through the product's insulation under normal and single fault conditions.

ENCLOSURE LEAKAGE TEST

The Enclosure Leakage test places the MD from one or more points on a DUT's chassis to the neutral side of the line. In this configuration, power is applied to the DUT at 110% of the nominal voltage level using an isolation transformer. The MD is used to measure the amount of leakage current flowing from the enclosure, excluding applied parts accessible to the operator or patient to ground or to another part of the enclosure



Neutral (S1)	Polarity (S2)	Ground (S3)
OPEN	NORMAL	OPEN
OPEN	REVERSED	OPEN
OPEN	NORMAL	CLOSED
OPEN	REVERSED	CLOSED
CLOSED	NORMAL	OPEN
CLOSED	REVERSED	OPEN
CLOSED	NORMAL	CLOSED
CLOSED	REVERSED	CLOSED

Table 1.0: Line Leakage Test Fault Conditions

under normal and single fault conditions.

APPLIED PART LEAKAGE TEST

The Applied Part Leakage test, also known as the Patient Leakage test places the MD from a patient-applied part (usually some sort of probe or meter that comes into direct contact with a medical patient's body) to the neutral side of the line. In this configuration, power is applied to the DUT at 110% of the nominal voltage level using an isolation transformer. The MD is used to measure the amount of leakage current flowing from applied part to ground under normal and single fault conditions.

PATIENT AUXILIARY LEAKAGE TEST

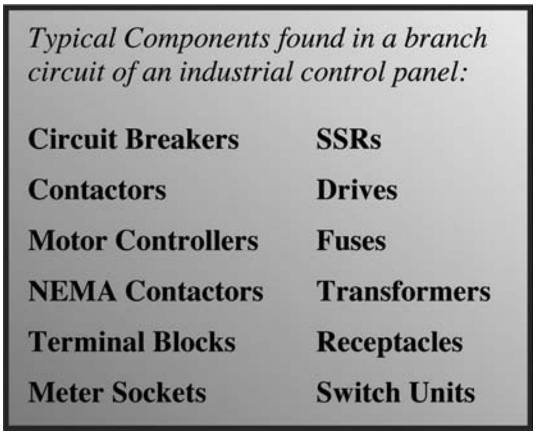
The Patient Auxiliary Leakage test places the MD in between 2 different applied parts that come into contact with a patient's body. In this configuration, power is applied to the DUT at 110% of the nominal voltage level using an isolation transformer. The MD is used to measure the amount of leakage current flowing from one applied part to another under normal and single fault conditions.

CONCLUSION

Although the Line Leakage test can seem somewhat confusing at times, it is an important test that should be given due consideration in any electrical safety testing routine. Technological advancements have made LLT much easier to perform and more manufacturers are performing LLT in both a lab and production environment. With some research and the right equipment, Line Leakage testing can be performed as quickly and easily as more common tests such as a Hipot or Ground Bond test. This means that the LLT can be added to a safety testing routine, without negatively impacting throughput and the addition of the LLT to any safety testing routine will help make electrical products safer and more reliable. This will save money in the long run.

SHORT CIRCUIT CURRENT RATINGS & SOLID STATE RELAYS

Dr. Oscar Montero, Crydom, Inc.



Typical Components found in a branch circuit of an industrial control panel:

- **Circuit Breakers**
- **Contactors**
- **Motor Controllers**
- **NEMA Contactors**
- **Terminal Blocks**
- **Meter Sockets**
- **SSRs**
- **Drives**
- **Fuses**
- **Transformers**
- **Receptacles**
- **Switch Units**

NEW CHALLENGES FOR INDUSTRIAL PANEL BUILDERS

The 2005 National Electrical Code now requires most control panels to be marked with their short-circuit current rating (SCCR). This change affects all industrial control panels (409.110), industrial machinery panels (670.3(A)), and non-residential HVAC equipment rated greater than 60A (440.4(B)). Furthermore, all industrial control panels listed to UL508A must be marked with their SCCR. Supplement SB in UL508A, which became effective on April 1, 2006, is referenced by the NEC as an approved method for establishing the SCCR of a panel.

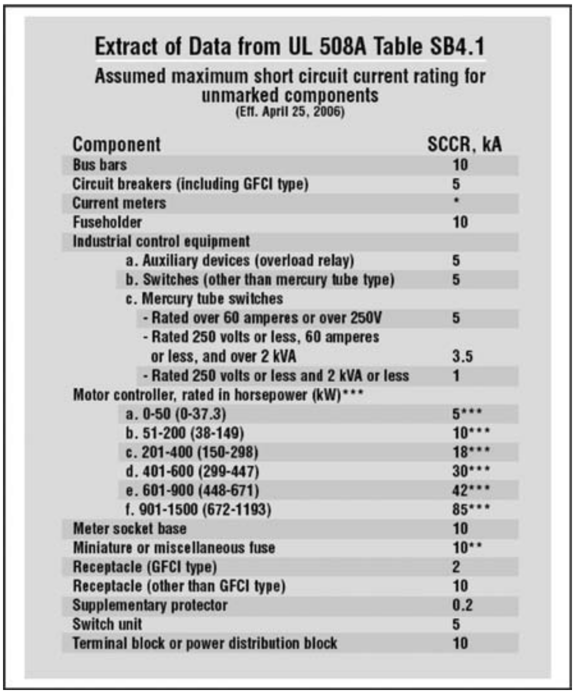
As with most every change to the NEC, safety is the primary concern of this new requirement. Under abnormal operating conditions, such as an electrical fault, a control panel may be subjected to thousands of amperes of let-through current before any protective device(s) inside the panel clears the fault. Such an event may cause severe damage to power components and electrical wiring, which can compromise the integrity of the Panel and result in injury to nearby personnel.

Proper matching between the maximum available current from the power supply and the SCCR for the panel is fundamental to ensure safety. From the Panel users point of view, Panels with a higher SCCR allows them the flexibility to connect their Panel to electrical systems with different available currents. From the Panel builder's point of view, establishing this higher SCCR may represent significant challenges and additional costs.

ESTABLISHING THE SCCR FOR CONTROL PANELS

Even though supplement SB from UL508A defines how the SCCR for an Industrial Panel is established, determining the Panel's actual SCCR may not be so straightforward. The simplest method to obtain the Panel's rating is by analyzing the individual power components in each branch of the circuit. The component with the lowest rating determines the SCCR for the entire branch. Subsequently, the branch with the lowest rating determines the SCCR for the entire panel.

Despite the fact that the SCCR rating for SSRs was not available in the past (nor was such a rating required) it is obvious from the above example that this is a critical part of determining the rating for the entire panel. Per UL508A supplement SB, components that do not have such a rating are given one based upon their specific category. SSRs, which do not have a specific category, are considered to fall under "Switches", "Switch Units", or "Motor Controller, 0-50HP". The rating for unmarked components in these categories is 5kA, and the use of such component in a branch circuit effectively reduces the entire



Extract of Data from UL 508A Table SB4.1

Assumed maximum short circuit current rating for unmarked components

(Eff. April 25, 2006)

Component	SCCR, kA
Bus bars	10
Circuit breakers (including GFCI type)	5
Current meters	*
Fuseholder	10
Industrial control equipment	
a. Auxiliary devices (overload relay)	5
b. Switches (other than mercury tube type)	5
c. Mercury tube switches	
- Rated over 60 amperes or over 250V	5
- Rated 250 volts or less, 60 amperes or less, and over 2 kVA	3.5
- Rated 250 volts or less and 2 kVA or less	1
Motor controller, rated in horsepower (kW)***	
a. 0-50 (0-37.3)	5***
b. 51-200 (38-149)	10***
c. 201-400 (150-298)	18***
d. 401-600 (299-447)	30***
e. 601-900 (448-671)	42***
f. 901-1500 (672-1193)	85***
Meter socket base	10
Miniature or miscellaneous fuse	10**
Receptacle (GFCI type)	2
Receptacle (other than GFCI type)	10
Supplementary protector	0.2
Switch unit	5
Terminal block or power distribution block	10

panel to the same rating.

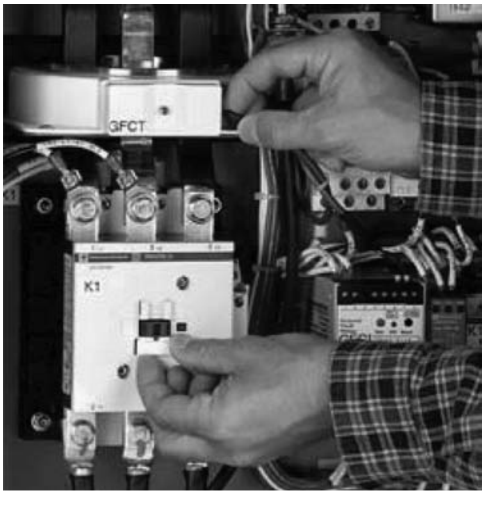
It must be realized that any rating from this table is subject to meeting what UL defines as conditions of acceptability. It is strongly recommended to check with UL about those conditions for any unmarked component that may be included in the Panel. Moreover, it should be noticed that the rating assigned to the SSR may have an impact on determining the rating for the whole Panel, as will any other power component inside the Panel.

ESTABLISHING THE SCCR FOR SOLID-STATE RELAYS

Per UL508A, short-circuit current ratings can be conveniently established for individual power components, or for combination of power components, or for the Control Panel as a whole. Crydom has elected to test a combination of SSRs with protective devices (fuses initially) in order to meet the conditions of acceptability necessary to assign the standard 5kA rating to the combination. However, most Crydom customers desire a SCCR rating higher than 5kA for their panel in order to be more competitive in the market. For this reason, Crydom is undertaking a series of tests in order to significantly increase the UL approved SCCR ratings for their relays.

The tricky part is selecting the right fuse for not only the application, but also for the desired SCCR rating for the combination. It is understood that under sizing the fuse may compromise performance, while over sizing the fuse may impact the safety of the Panel. Not to mention add unnecessary cost. To further complicate the issue, fuses of the same physical size may have different current ratings (i.e. a 60A fuse is the same physical size as a 45A fuse). This is a significant UL concern, as field service technicians could easily replace a fuse with one of identical size but having a higher current rating. Such an error could potentially result it damage to the relay, the load, or nearby personnel.

Therefore, UL requires that the relay-fuse combination be tested with an "umbrella fuse". That is, the fuse used in the combination must have the highest possible current rating available for that particular fuse package. Since UL approval with a rated fuse covers all fuse ratings up to that value, the "umbrella fuse" method adequately addresses this concern. Crydom's test plan involves multiple relays of different load-current ratings in combination with the highest possible "umbrella fuse" combination. This not only meets UL's safety requirements, but also provides panel builders with flexibility in selecting the right relay for their application and their specific SCCR requirements.



Similar to fuses, solid-state relay manufacturers tend to follow a typical industry-standard footprint. However, unlike fuses, each manufacturer's relays may have significant design differences that affect thermal performance, power dissipation, mechanical stress/fatigue, etc. Therefore, the "umbrella" concept does not apply in the same manner as it does for fuses. So simply substituting one relay with an "equivalent" relay from another manufacturer will not likely result in an equivalent short-circuit current rating.

It should be remembered that SCCR is strongly related to safety, and therefore great caution must be used when changing solid-state relays in control panel.

WHO SHOULD BE CONCERNED OVER SCCR?

While the new NEC code focuses primarily on the North American market, Panel Builders selling outside of the US may also be affected by the change. Any panel requiring UL Listing, regardless of its final destination, must be marked with a SCCR. In addition, some regions outside of the US may enforce NEC 2005 as an additional safety measure for local installations. Panels in such locations must also have their SCCR clearly marked.

To add to the confusion, some states in the US have not yet adopted NEC 2005. Therefore, they do not yet require the SCCR marking on panels. However, as stated above, a UL Listed panel installed in that particular state must have an approved SCCR, regardless of the state's regional requirements.

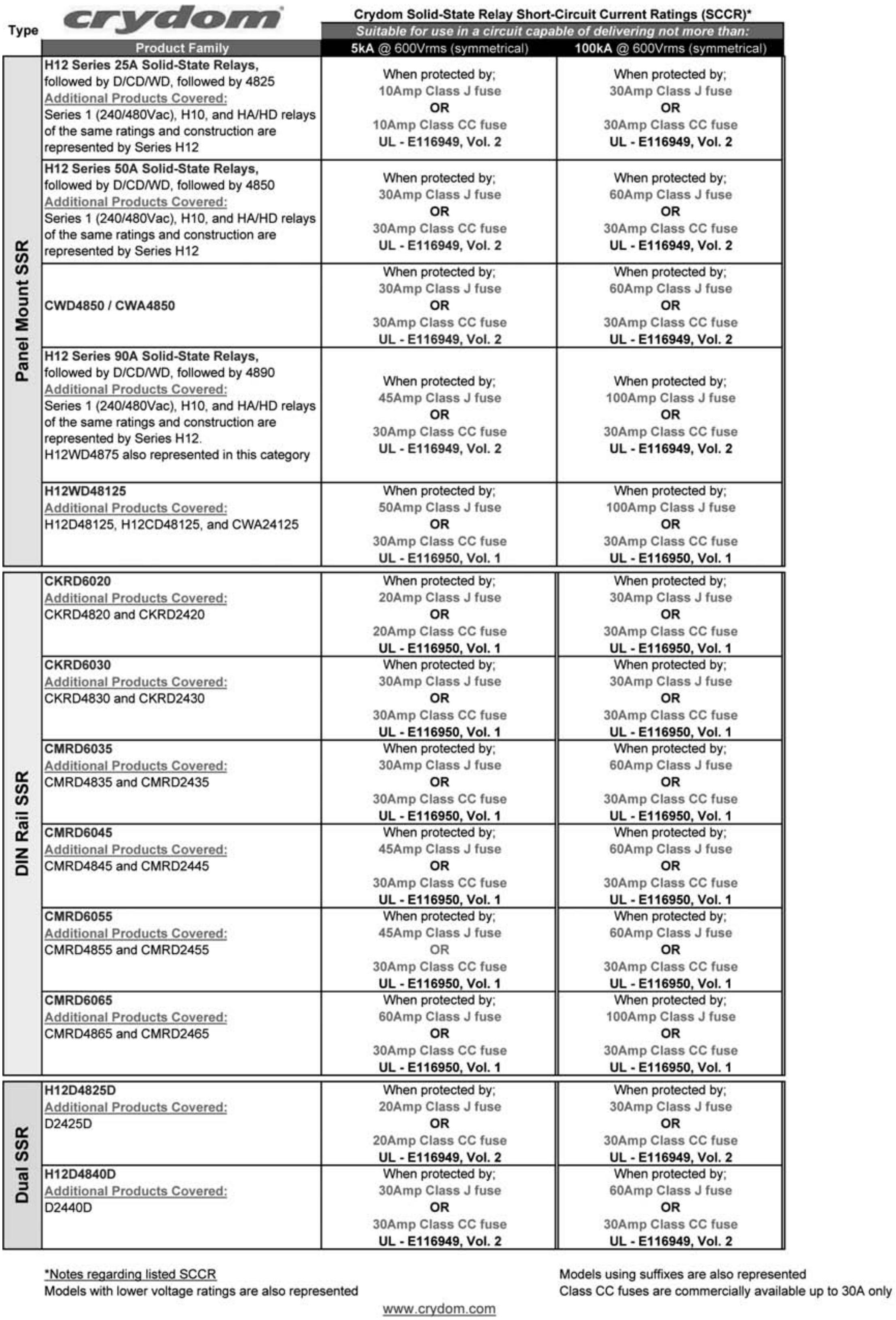
SCCR FOR CRYDOM SOLID-STATE RELAYS

To date, testing for selected combinations of solid-state relays and fuses performed in an UL approved Schneider Electric Laboratory and witnessed by an UL representative has yielded the results shown in the table(s) below. Current and potential customers of Crydom solid-state relays should note the following:

- Equivalent relays from different manufacturers may not have similar SCCR. Caution is advised when relays are rated in combination with protective devices.
- The following table(s) contains both UL approved and manufacturer approved relay/fuse combinations. The manufacturer approved combinations are highlighted/italicized. The table(s) also contains generic and specific fuse information. Panel builders can use the generic information in their manufacturing procedure. For example, generic information is when protected by a 30Amp Class J Fuse. In these cases, it is allowed to use fuses of the same class with lower ratings.

Class J Fuses

- Data for a specific manufacturer's fuse (i.e. "when protected by a AJT80 Class J Fuse") was obtained in a manner identical to the procedure for generic information (i.e. "when protected by a ≤30A Class J Fuse"). As with the generic evaluation, the specific testing was also witnessed by a UL representative. However, UL does not allow for a SSR to be marked with a specific manufacturer's fuse. Regardless, the information remains valuable, as it may be used only as a reference to help panel builders better understand the limits of the branch where the specific relay-fuse combination is located. This information will help in determining the panels overall SCCR in cases where the panel is tested as a complete system.



crydom

Crydom Solid-State Relay Short-Circuit Current Ratings (SCCR)*

Suitable for use in a circuit capable of delivering not more than:

Type	Product Family	5kA @ 600Vrms (symmetrical)	100kA @ 600Vrms (symmetrical)
Panel Mount SSR	**H12 Series 25A Solid-State Relays,** followed by D/CD/WD, followed by 4825 Additional Products Covered: Series 1 (240/480Vac), H10, and HA/HD relays of the same ratings and construction are represented by Series H12	When protected by; 10Amp Class J fuse **OR** 10Amp Class CC fuse **UL - E116949, Vol. 2**	When protected by; 30Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116949, Vol. 2**
	H12 Series 50A Solid-State Relays, followed by D/CD/WD, followed by 4850 Additional Products Covered: Series 1 (240/480Vac), H10, and HA/HD relays of the same ratings and construction are represented by Series H12	When protected by; 30Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116949, Vol. 2**	When protected by; 60Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116949, Vol. 2**
	CWD4850 / CWA4850	When protected by; 30Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116949, Vol. 2**	When protected by; 60Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116949, Vol. 2**
	H12 Series 90A Solid-State Relays, followed by D/CD/WD, followed by 4890 Additional Products Covered: Series 1 (240/480Vac), H10, and HA/HD relays of the same ratings and construction are represented by Series H12. H12WD4875 also represented in this category	When protected by; 45Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116949, Vol. 2**	When protected by; 100Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116949, Vol. 2**
	H12WD48125 Additional Products Covered: H12D48125, H12CD48125, and CWA24125	When protected by; 50Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**	When protected by; 100Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**
DIN Rail SSR	**CKRD6020** Additional Products Covered: CKRD4820 and CKRD2420	When protected by; 20Amp Class J fuse **OR** 20Amp Class CC fuse **UL - E116950, Vol. 1**	When protected by; 30Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**
	CKRD6030 Additional Products Covered: CKRD4830 and CKRD2430	When protected by; 30Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**	When protected by; 30Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**
	CMRD6035 Additional Products Covered: CMRD4835 and CMRD2435	When protected by; 30Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**	When protected by; 60Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**
	CMRD6045 Additional Products Covered: CMRD4845 and CMRD2445	When protected by; 45Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**	When protected by; 60Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**
	CMRD6055 Additional Products Covered: CMRD4855 and CMRD2455	When protected by; 45Amp Class J fuse OR 30Amp Class CC fuse **UL - E116950, Vol. 1**	When protected by; 60Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**
	CMRD6065 Additional Products Covered: CMRD4865 and CMRD2465	When protected by; 60Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**	When protected by; 100Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116950, Vol. 1**
Dual SSR	**H12D4825D** Additional Products Covered: D2425D	When protected by; 20Amp Class J fuse **OR** 20Amp Class CC fuse **UL - E116949, Vol. 2**	When protected by; 30Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116949, Vol. 2**
	H12D4840D Additional Products Covered: D2440D	When protected by; 30Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116949, Vol. 2**	When protected by; 60Amp Class J fuse **OR** 30Amp Class CC fuse **UL - E116949, Vol. 2**

*Notes regarding listed SCCR

Models with lower voltage ratings are also represented

Models using suffixes are also represented

Class CC fuses are commercially available up to 30A only

www.crydom.com

GENERATOR MAINTENANCE TESTING

By G. Klempner and I. Kerszenbaum

For the purpose of this article, generator maintenance testing refers to tests that are done generally off line or at some special condition, as opposed to on-line testing which is actually a form of monitoring for diagnostic purposes while the generator is producing power. However, there are certain on-line tests that are done and classified as testing rather than monitoring, because they are not done on a full-time basis, meaning continuously monitored. Those types are discussed here as well.

Tests on large turbogenerators are a very serious business. Improper testing or test preparation can cause expensive, unnecessary losses to the machine and expose the personnel to lethal dangers. Hence, tests must be carried out only by well-trained professionals, following all relevant and applicable rules and standards.

11.1 STATOR CORE MECHANICAL TESTS

11.1.1 CORE TIGHTNESS

Stator cores can become loose from vibration and thermal cycling. If they do, then there is concern for inter-laminar fretting of the insulation coating on the individual laminations. Loss of the inter-laminar insulation can cause shorts and local overheating of the core. To ensure the core is tight, a stator core tightness test can be done when the rotor is removed.

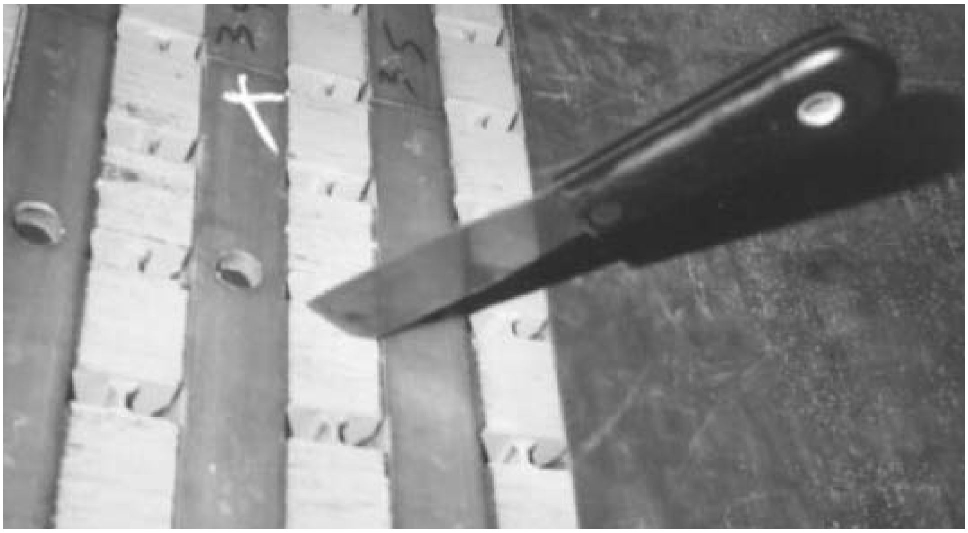


Fig. 11.1 Stator core tightness testing by knife insertion method.

The test is done by inserting a thin, tapered, and hardened steel knife blade between laminations to determine the degree of looseness in the stator iron (Fig. 11.1).

This test requires some experience to get a “feel” for what is or is not loose. However, in general, one should only be able to get the knife blade just into the core, if at all, and not be able to push it any distance inward, in the radial direction.

The testing should be repeated all around the circumference of the stator bore, and over the full length of the core, in random locations. Particular attention should be paid to the core ends, as this is where the majority of loosening generally occurs.

When looseness is found in the core, there are numerous methods available for remedying the situation. These include localized core stemming with shaped epoxy/glass inserts, retorquing of the core, and so on, up to re-stacking of the core iron.

11.1.2 CORE AND FRAME VIBRATION TESTING

The maximum vibration of the stator core and core frame should be less than 50ºm (about 2 mils) peak to peak (unfiltered), with no natural resonance within the frequency ranges of 50-75 Hz and 100-140 Hz for 60 Hz systems, and about 40-65 Hz and 80-120 Hz for 50 Hz systems. The problems associated with high vibrations are premature stator core inter-laminar and stator winding insulation wear, and structural problems with the core and frame. To maintain low vibration and avoid problems, it is best to have a tight core and to have good mechanical coupling between the core and frame. This ensures that no wear occurs between the two components at the keybars. Low absolute vibrations and low relative vibration between the core and frame, with the two components in phase, is a good indicator that the core and frame structure is sound.

Testing can be done off line or on line. However, for either type of test, vibration transducers (accelerometers) must be mounted on the core and frame, internal to the machine. This includes the stator center, both ends, and locations on the circumference based on the nodal vibration patterns of the stator (four nodes for two-pole machines and eight nodes for four-pole machines). The vibrations are generally measured in the radial and tangential directions when looking toward the end of the machine. In addition it is desirable to use a number of portable, magnetic based transducers, which may be moved around the outside of the generator casing, to ensure complete analysis of the machine.

Off-line testing is not generally done unless there is a known problem with core and frame vibration. The excitation source must be artificially applied in this method, and there are a couple of ways to accomplish this. One is to simply strike the frame with a heavy rubber hammer and measure the frequencies where the vibrations peak. However, this does not usually produce a significant result because the stimulus is so small. The other method is to attach a shaker device to the frame to stimulate the stator at a fixed frequency, and then measure the frequencies where the vibrations peak. The shaker method generally produces good results because there is a significant stimulus and it can be controlled. The problem with this type of testing is that it does not give an accurate picture of the true vibration of the core and frame in operation.

On-line testing is generally the best way to get a complete vibration analysis of the core and frame. With on-line testing it is possible to look at all operating modes of the stator and determine which parameter has the most influence on vibration. During testing the variable parameters are stator current, field current, hydrogen pressure, and hydrogen temperature. In some cases it has also been useful to valve out individual hydrogen coolers, successively, to change the cooling pattern and determine its effect on the core and frame vibration.

When core and/or frame vibrations are present, it is necessary to determine if the vibrations are most prevalent on the core or frame, and if the two components require better coupling to each other. The possibilities of what may be found on any individual machine are too vast to cover here. However, as a rule-of-thumb, it is often found that the core and frame will have a natural frequency that is too close to the forbidden zones, and that they do require some artificial means to ensure better mechanical coupling between the two. In such cases, vibration damping is also usually required. When trying to dampen excessive vibrations, there are two methods employed. The first method requires adding mass to lower the natural frequency. The second method entails stiffening the structure to raise the natural frequency. Adding mass can be difficult if there is no good place to attach it, and stiffening can sometimes cause problems with overstressing the frame welds, causing them to crack.

Stator core and frame vibration problems are very complex to analyze, and even more complex and expensive to solve. They should be addressed on a machine-to-machine basis, as each case will be unique.

11.2 STATOR CORE ELECTRICAL TESTS

11.2.1 EL-CID TESTING

The EL-CID (Electromagnetic-Core Imperfection Detector) technique was originally devised as portable test equipment for inspection and repair of rotating electric machine stator cores. It was devised as a low excitation power alternative to the high power level stator core flux test, for looking for stator core inter-laminar insulation problems. Its application has been shown to be applicable to turbine generators, hydraulic generators, small generators, and large motors.

However, here we are confined to the class of large two and four pole, round-rotor machines, commonly referred to as turbine-driven generators.

The information contained in this section is a brief discussion of the EL-CID test technique and basic interpretation of results.

Traditionally stator core inter-laminar insulation testing has been done using the “ring” or “loop” flux test method, in which rated or near-rated flux is induced in the stator core yoke. This, in turn, induces circulating currents from the faulted area usually to the back of the core, at the core-to-keybar interface (Fig. 11.2).

These circulating currents cause excessive heating in areas where the stator iron is damaged. The heat produced is generally detected and quantified using established infrared techniques. This method has been proved to be successful over the years, but it requires a large power source and considerable time, manpower and resources to complete.

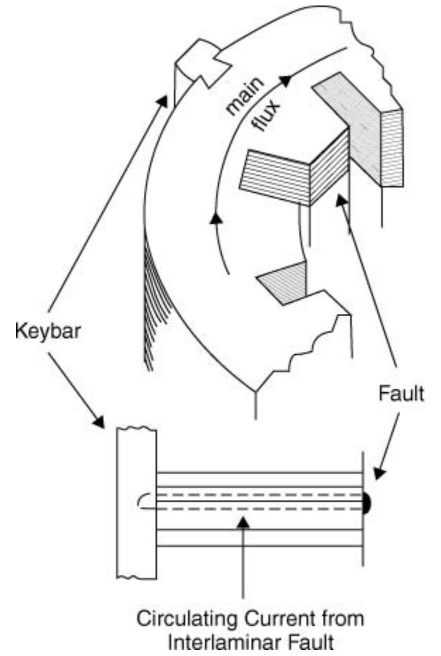


Fig. 11.2 Stator core fault current path from fault to core back at the keybars, by induced flux. (Courtesy of ADWEL International).

Starting in the early 1980s, the EL-CID test has been developed as an alternative to the ring flux test. The technique is based on the detection of core faults by measuring the magnetic flux resulting from the current flowing in the fault area, at only 3 to 4% of rated flux in the core. Furthermore the test usually requires only two or even one man to complete (using the latest version) in less than one eight-hour shift.

EL-CID TEST PROCEDURE

The level of excitation to produce the desired flux in the stator core-back area is generally determined by a combination of the stator design parameters, and the power supply available to achieve the required flux level. For most generators, the standard 120 V AC (North America, etc.) or the 230 V AC (Europe, etc.) outlet, with a current capacity of 15 to 20 amp is usually adequate.

The characteristics of most stators are such that four to seven turns of a #10 AWG insulated wire (2.5 mm2) can be used to carry the excitation current for the test. The winding is then energized to the required volts per turns to produce approximately 3 to 4% of rated flux, usually corresponding to around 5 volts per meter across the stator iron. A Powerstat or Variac is best used for voltage and supply current control.

The signal-processing unit of the EL-CID test equipment measures detected fault current (in quadrature mode) in mA. By theory and experimentation, a measurement of at least ±100 mA is required at 4% excitation of the core before it is considered that the core has significant damage affecting the interlaminar insulation.

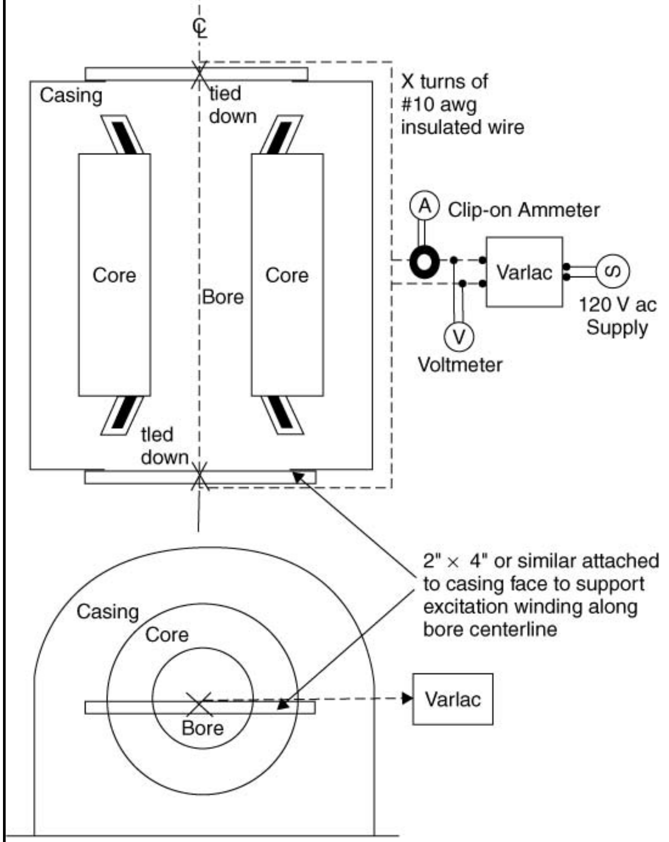
The excitation winding and power supply are set-up during the test as shown in Figure 11.3. The EL-CID equipment is set up as shown in Figure 11.4 (original analog set) and Figure

11.5 (newer digital set).

In the older analog sets, a separate coil is placed in the bore over undamaged iron as shown in Figure 11.4 to supply the reference signal. In the newer digital version, a CT (shown in Fig. 11.5) is placed around the excitation winding to reference the supply signal. The CT was also an option on later analog sets. The digital equipment uses a laptop computer to store the axial traces, whereas a plotter was used in the original version.

The sensor head (chattock potentiometer) is pulled axially along the core at a speed slower than one meter every twenty seconds and always bridging two stator teeth as shown in Figure 11.6. (The slower speed is important, as the standard chattock coil has a magnetic sense area of only 4 mm diameter, and both the digital and analog systems have a definite time needed to record the phase/quad signals to sufficient resolution. The digital set records the phase and quad values every 2 mm. Any faster testing results in some missed test points in the digital system or potential inaccuracy due to settling time on the analog system).

The fault current signal is read directly off the signal processor meter, and input to a computer or chart recorder to trace out the readings as a function of the axial position along the stator core. When the sensor head is over undamaged iron, the meter should read zero if it is calibrated previous to the test for a condition where no fault current is circulating. In actual practice, no insulation system is perfect, and some background signal is usually detected. In addition, the contact resistance of the core to keybar interface is not zero and can be found to vary between near 0 to 2 ohms. This also affects the EL-CID signal that is measured. Usually anywhere from a 0 to ±20 mA EL-CID signal (in quad mode) is found to be normal when good core is measured.



℄
Casing
tied down
X turns of #10 awg insulated wire
Core
Bore
Core
A
Clip-on Ammeter
Varlac
S
120 V ac Supply
V
Voltmeter
tied down
2" × 4" or similar attached to casing face to support excitation winding along bore centerline
Casing
Core
Bore
Varlac

Fig. 11.3 Excitation winding and power supply setup for EL-CID testing.

EL-CID is somewhat similar to the rated flux test where the undamaged iron slowly heats up producing a background level due to eddy current losses in each laminations. During flux testing, this is recorded as the ambient core temperature rise. Where there is damaged or deteriorated core insulation, the core overheats and is detected as a hot spot above core ambient due to high fault currents circulating locally. In the EL-CID test,

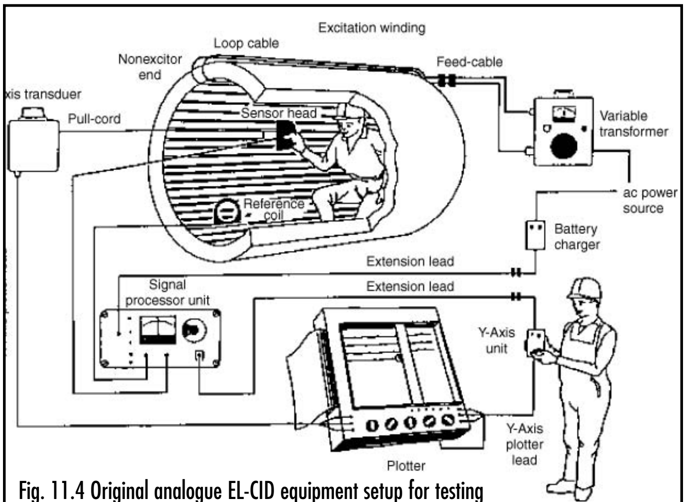


Fig. 11.4 Original analogue EL-CID equipment setup for testing large turbogenerators. (Courtesy of ADWEL International).

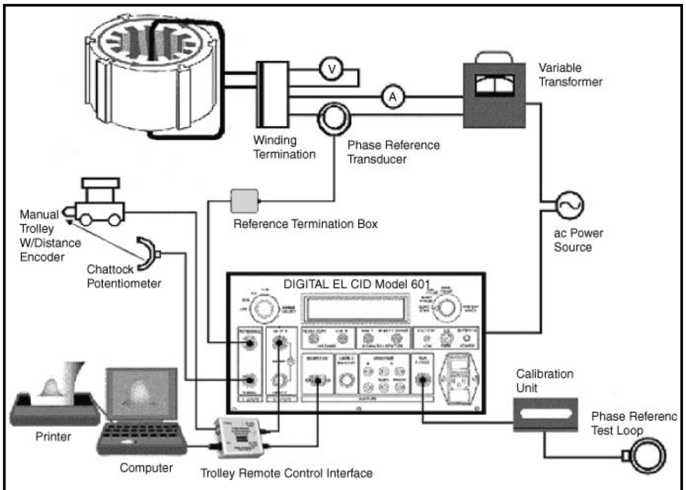


Fig. 11.5 Digital EL-CID equipment setup for testing large turbogenerators. (Courtesy of ADWEL International).

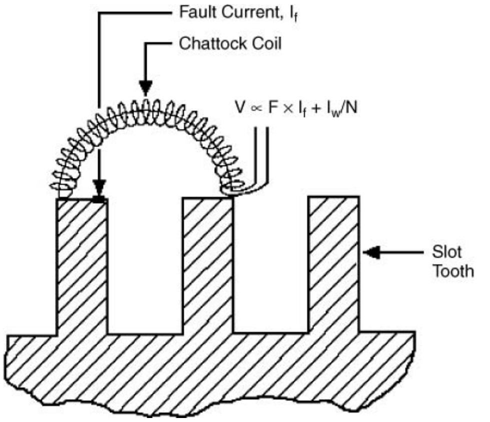


Fig. 11.6 EL-CID sensor head (chattock potentiometer) basic circuit. (Courtesy of ADWEL International).

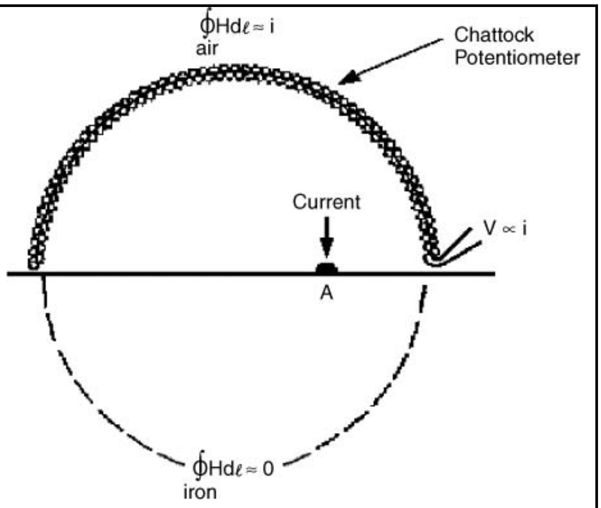


Fig. 11.7 EL-CID sensor coil (chattock potentiometer) winding voltage and induced current is proportional to the current flowing in the fault. The iron portion of the circuit is neglected due its low magnetic reluctance, compared to air. (Courtesy of ADWEL International).

when the sensor head is placed over damaged core areas, the primary indication of a fault is obtained by detecting the flux produced by a current flowing in phase quadrature with respect to the excitation magnetizing current (the phase current). This flux is then converted back to an indicated current (the quad current) assumed to be flowing in the fault (Fig. 11.7). For this reason the quad current detected by the EL-CID processor is frequently referred to as the fault current (although for large faults the phase current may be affected as well, especially where the fault current path is highly inductive). The quad current is indicated on the signal processor meter and the traces recorded on the plotter (original analog EL-CID equipment) or computer (newer digital EL-CID equipment).

EL-CID EXPERIENCE

EL-CID has proved to be extremely reliable in detecting and locating core problems. It can cut the time and manpower required for core testing to within one eight-hour shift, where a flux test may have taken a few days to set up, and then a day to test, and another day to dismantle the test equipment.

In the large majority of the EL-CID tests on turbogenerator machines, experience has been that EL-CID is very reliable in determining that actual core faults or inter-laminar insulation deterioration exists. In other words, if a core defect exists, then EL-CID is likely to find it. Then, if the core is indicated to be defect free by an EL-CID test, there is a very high probability that it actually is free of defects.

Large signals may be found at tooth-top locations on the core, and only indicate a significant surface fault. Local surface faults are generally indicated by faults that show very localized signals, either high or low in magnitude and positive in polarity, if within the test coil span (assuming the standard EL-CID test setup).

Deeper faults can generally be seen over a larger scanning area, and also often become opposite in polarity as the sensor head gets away from the fault area.

This is because the fault is outside the flux path of the chattock coil sensing the fault current, and the magnetic potential difference is reversed.

Figure 11.8 shows a general basic interpretation of the EL-CID signals that can be expected to be seen based on fault location. The magnitudes in Figure 11.8 are only relative to one another to give an idea of what might be expected for faults of roughly the same severity at different locations. The peaks, and widths of the peaks, will vary from fault to fault as their size varies, and as they are more or less severe.

Attempts have been made to correlate EL-CID signal readings to temperatures that would be created in the defect area during a flux test. The basic premise of the EL-CID test significance level of ±100 mA is that this level represents a 5 to 10°C temperature rise, as seen on flux tests, and therefore it is just at the level of temperature rise where most OEMs and experienced stator core experts should carry out repairs to the core iron.

There are a number of issues that makes questionable the assumption that correlates EL-CID's signal to temperature. First, many core testers carry out flux tests at widely differing flux levels. Some prefer to test at 100% of rated flux level, while others test at about the 80% level. Different operators also apply the flux test over widely varying time periods. Yet, by all indications, all seem to work on the same temperature rise criteria. Obviously a 10°C rise at 100% of rated flux is much less significant than at 80% of rated flux. This is so because the 80% level is generally at the knee of the B-H curve and the curve is exponential.

Increasing to 100% when the temperature rise is already 10°C will increase the temperature in the fault.

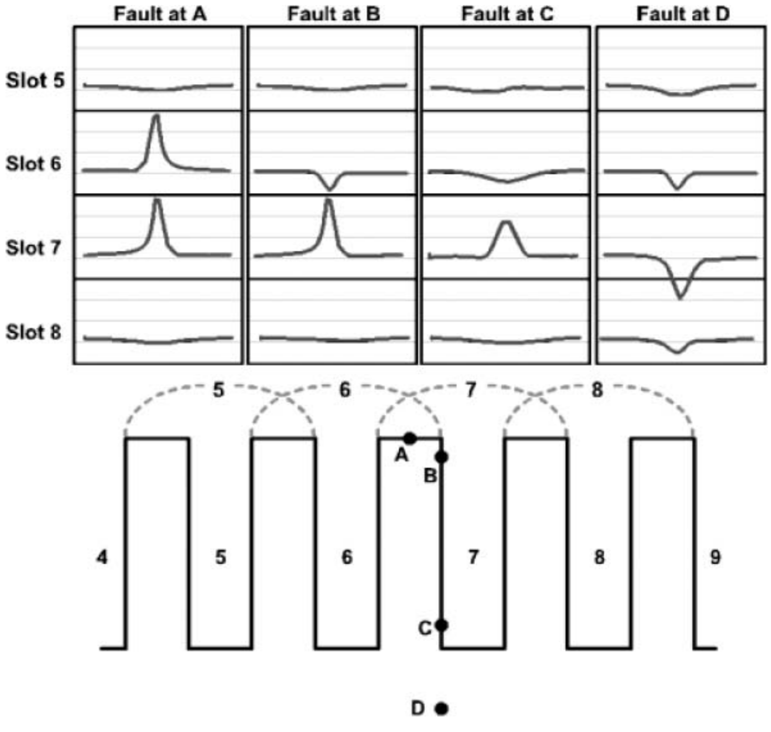


Fig. 11.8 EL-CID signal interpretation of surface and deep faults.

There is also the influence and undetermined significance of core-to-keybar contact resistance at the back of the core. The concern here is that the resistance can be generally measured to vary from nearly 0 to 2 ohms, which will affect the EL-CID signal as well as the temperature measured during the flux test.

For the low flux levels of the EL-CID test, the core-to-keybar contact resistance may be quite significant. This is one of the unknowns for which there is little data one way or another. But it should be noted that on ungrounded cores (i.e., cores with insulated keybars and infinite core to keybar contact resistance), the EL-CID and the flux test are both ineffective unless there are two faults in proximity that allow circulating current to flow and hence be detected by either test. This has been proven by tests done on ungrounded cores, where single faults do not show up until the core is artificially grounded at the back near the keybar behind the location of the fault.

Generally, there is only one keybar that is grounded on such core arrangements (for purposes of the stator ground fault relay), and the testing for single faults is effective in that lamination region only. To test such a core arrangement by either EL-CID or flux test, the core must be purposely grounded at the back, between every keybar, circumferentially, and on every lamination axially. One can easily see the difficulty in this, as this arrangement is not even possible on most stator designs, because of the frame construction. One has to consider this possibility when purchasing a new stator. If a single core fault occurs, then the insulated core may allow operation where the grounded core would fail based on the progression of the fault. However, if two faults occur in the same proximity, then a much more severe fault may occur and go undetected until the effect of the failure causes additional collateral damage, which takes the machine out of service. This is generally a matter of user preference and both philosophies are sound, each in its own way.

In addition there is the problem that core faults can manifest themselves in many forms and levels of severity. It is not uncommon for a surface iron smudge to show a very high EL-CID signal and yet not produce much heat when looked at under infrared in a flux test. The opposite is true as well. It is not uncommon for an EL-CID signal that is not much higher than the manufacturer's recommended significance level to produce significant heat. In particular, with very small faults on the surface where EL-CID does not produce a significant signal, there are sometimes high-spot temperatures detected by infrared, but there is insufficient power to cause damage.

One advantage is that EL-CID can detect deep-seated faults, which may often not show as a particularly large temperature rise on the surface but can be damaging to the body of the core or adjacent conductor bar insulation. This is due to the fact that the attenuation of EL-CID signals is generally less than the attenuation of temperature rises with depth of fault.

The difficulty in correlating EL-CID and Flux test temperatures therefore comes from many issues as stated above and a number of other possible influences as listed below:

- Core-plate grade (i.e., grain oriented vs. nonoriented steels);
- Lamination insulation grades;
- Axial length of the fault;
- Total size of the fault;
- Electrical resistance of the inter-laminar fault (i.e., deteriorated or fretted insulation type damage as opposed to hard-contact, low-resistance type faults);
- Geometry differences in core structure from one machine to another;
- Limitations of the earlier EL-CID test equipment, in relation to the size of the chattock coil itself and the relative size of any fault being measured.

(Current standard Chattock coils have only a 4 mm diameter magnetic sense area, and thus are able to detect very small faults, particularly, if the suspected fault area is investigated/scanned slowly enough.).

All these issues can significantly affect both the observed EL-CID signal and the temperature produced during a flux test. Some are better known and quantified than others. Trying to correlate temperatures to EL-CID signals under so many variables is difficult, unless all of these parameters can be taken into account. In other words, the core under test must be well known to be able to make such a correlation.

There is one other factor regarding EL-CID signal interpretation, and it has to do with readings taken in the phase mode, as opposed to the normal quad mode reading that Figure 11.8 is based on. Basically when a stator has, for example, four turns of an excitation winding and is carrying 12 amps, then it has an excitation level of 48 amp-turns. When the EL-CID signal processor is set to phase mode and a reading is taken from tooth center to tooth center across one slot, a signal of (48 A-T divided by 48 slots) 1 amp should be read. Generally, for most fault areas this is the reading that will be evident. However, in some cases, much higher current is read in the phase mode than the simple magnetic potential based on excitation and slot geometry. One of the things that has been seen when this type of situation occurs is that very high quad readings are often also present, and the fault is usually at the bottom of the slot or in the core yoke area. Correspondingly there is not always much heat given off during flux testing, and the two tests do not always correlate when this occurs. There is very little experimental data on this point, and again it shows that some uncertainties remain in interpretation of EL-CID test results. It is believed that phase readings are also significant and should be factored into the test interpretation. Just what that interpretation should be is unclear to date, due to the difference in faults from case to case.

For the test interpreter probably the main difficulty is when nothing is known about the core under test, nor the type of fault found. The core defect is often not visible, and thus the tester is confounded in trying to determine is how deep it is and how severe it is. The general consensus of the people surveyed on this issue is that more often than not, they cannot tell how severe a detected fault is and must depend on a flux test with infrared scan in making that determination. The ring flux test remains the best test to determine the actual temperature rise of any fault, and whether repairs are required. If the fault is suspected to be deep-seated from the EL-CID test result, the ring flux thresholds should be appropriately adjusted. Once the core is repaired, an EL-CID test can usually show that the repair is successful by the absence of a defect signal. This is perhaps the real benefit of EL-CID testing.

There seems to be general consensus that if an EL-CID test is performed and no damage is found, then the core is defect-free. EL-CID has gained good credibility in its ability to determine and locate the presence of faults, and to verify successful repairs of faults. The general consensus also is that more work is required on EL-CID signal correlation with temperature rise in fault locations.

The general opinion to date is that both the EL-CID and flux testing together are still required to give the best information on any core defect found.

11.2.2 RATED FLUX TEST WITH INFRARED SCAN

The rated flux test is a high-energy test used to check the integrity of the insulation between the laminations in the stator core. It is also commonly referred to as the ring flux test, in which near-rated flux (normally about 80%) is induced in the stator core yoke. This, in turn, induces circulating currents and excessive heating in areas where the stator iron is damaged (Fig. 11.2). The heat produced is detected and quantified using established infrared techniques.

Flux is produced in the iron by looping a cable around the core in toroidal fashion (Fig. 11.9), and circulating a current at operating frequency. The flux required for the flux test is half the normal operating flux due to the difference in the way the flux is induced in operation (Fig. 11.10) from that of the flux test.

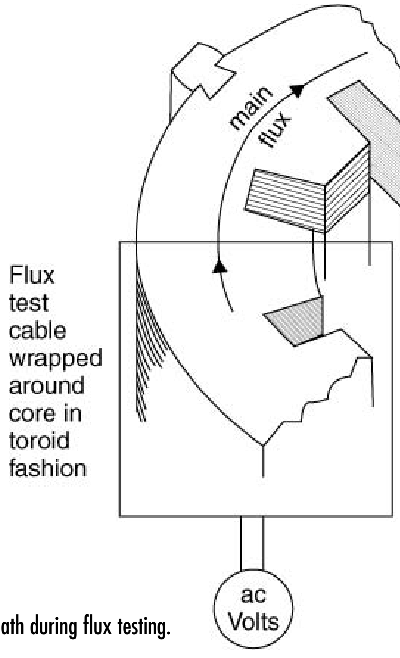


Fig. 11.9 Flux path during flux testing.

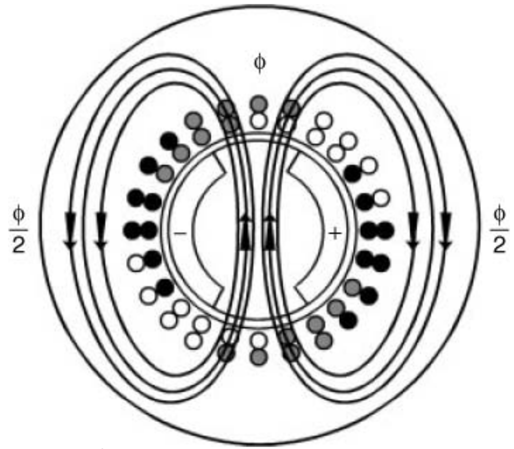


Fig. 11.10 Operational flux path.

The power supply for the cable is usually taken from two phases of one of the high-voltage breakers (i.e., 4 kV) in the plant, or a portable motor generator set.

The correct number of turns are looped around the core to produce the required level of flux. IEEE Std 432 [11] provides the following expression to find the rated volts per turn required on the stator core:

$$\text{Voltage per turn of test coil} = \frac{1.05 \times V_{LL}}{2\sqrt{3} \times K_w \times N}$$

where
VLL = line-to-line voltage
Kw = winding factor
N = number of turns per phase in series in the stator winding

As the equation shows, the available power supply voltage is divided by the calculated volts per turn above, to give the correct number of turns to loop through the core. If the number of turns includes a fraction, then the next highest number is used, to reduce the flux level to below 100% or below rated. Using too high of a flux level can create core damage, since there is no cooling on the core during the test.

Once the number of turns is known, the current capacity is required to size the cable and ensure the power source can handle the current that will be drawn.

Knowledge of the specific B-H characteristic of the subject core being tested is required for this. It cannot be stressed enough that the exact B-H characteristic of the stator core should be known in relation to the flux volts per turn as well as the current required from the power source (Fig. 11.11). In many instances it is unknown, and therefore the number of ampere-turns required must be estimated based on industry curves for the most likely grade of core-plate that will be used in the machine under the test. A higher end and lower end core-plate grade are usually selected to provide a range of possible operating characteristics for the subject core. These are selected to provide a range of possible excitation requirements, based on B-H curves taken from small and large turbogenerator applications.

From the winding configuration for the subject generator, the power supply available, and the B-H curves, an estimate can be made for the number of turns required to achieve the required level of flux for the test. This is generally in the 70 to 90% range of rated flux. The current that would be flowing in the flux cable will depend on the actual B-H characteristic of the stator iron and therefore, this must be carefully estimated for safety of both personnel and the equipment. When the B-H curve is in doubt, adding a higher number turns will reduce the level of flux. Then it follows to successively remove turns and keep recording the current attained as the flux volts per turn increases. Successive voltage application in this manner can be made until a B-H curve is created and the proper number of turns found (Fig. 11.11).

The flux test is set up as basically shown in Figure 11.12. The power supply is selected and connected as shown. The cable is wound through the stator bore the correct number of times, and connected back to the power supply. Protection for the test cable is set up to provide "ground fault" and "overcurrent." The stator core, frame, and windings were all grounded for their protection and that of the test personnel. The CTs should also shorted at the terminals and grounded.

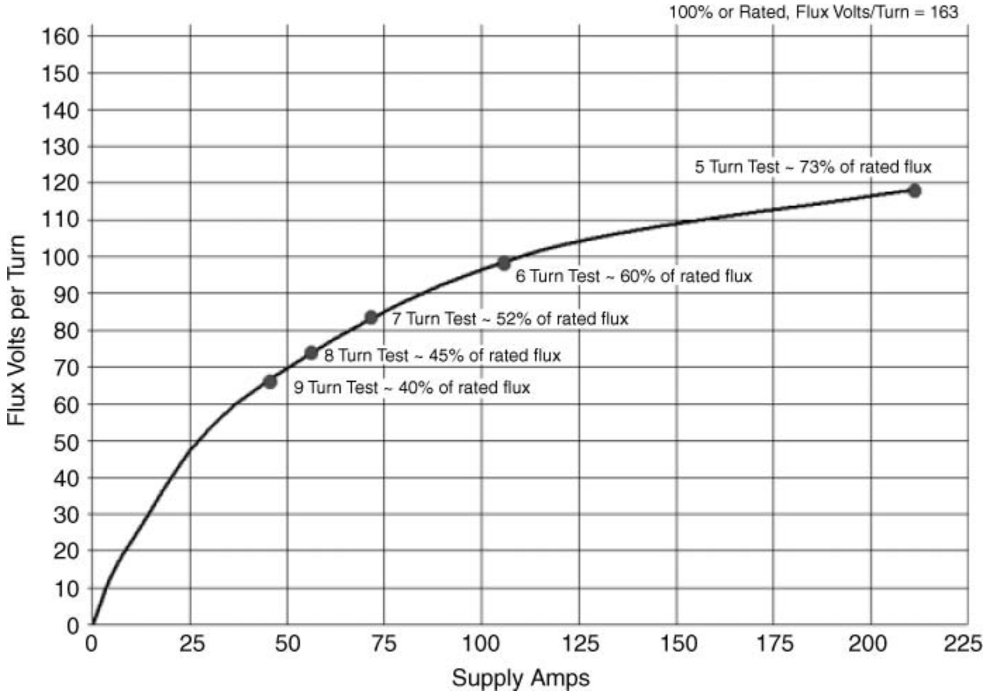


Fig. 11.11 B-H curve example showing the flux volts per turn, the percentage of rated flux, and the number of turns versus supply current.

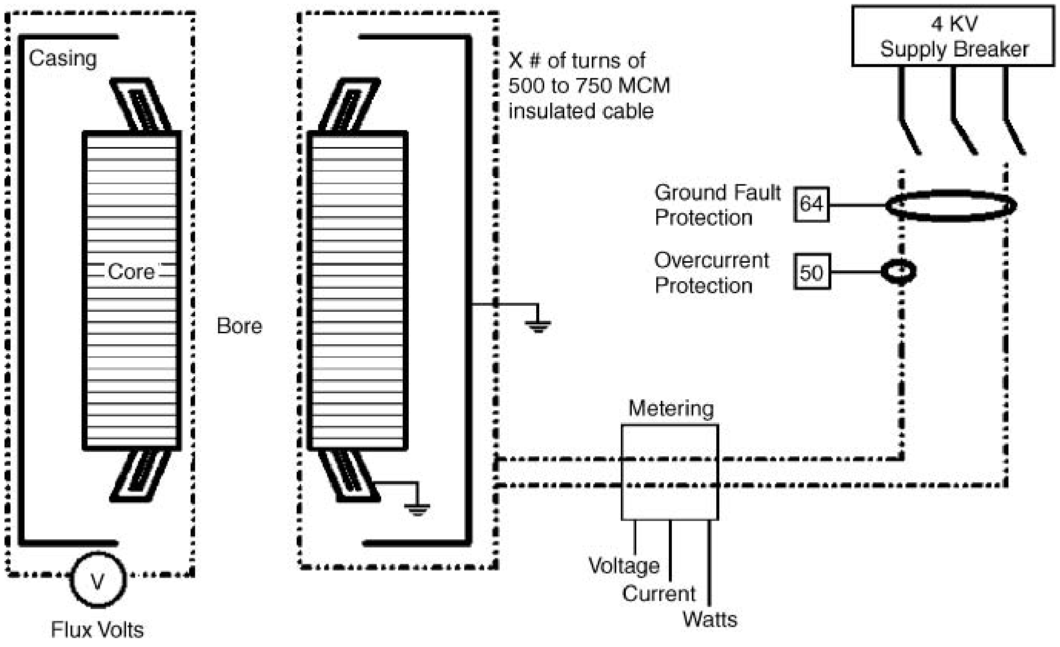


Fig. 11.12 Stator core, excitation, and protection setup for a flux test of a large turbogenerator stator core.

Metering is set up to provide measurements of supply voltage and current. A single loop of cable is installed additionally to measure the actual flux volts on the stator core during the test. This is done to provide an accurate measurement of the induce voltage across the core and the level of flux as well.

In some cases an infrared, nonreflecting mirror is used to monitor the temperature of the stator core when angled viewing from outside the stator bore is difficult (Fig. 11.13). The mirror provides a known surface to accurately measure the temperatures so that the absolute and relative rise of temperatures in the core defect areas can be recorded.

Once the flux is established in the core, it is kept for at least 30 minutes to 1 hour. The temperature of the core should be maintained within values not significantly higher than those encountered during operation. Under these conditions, the temperature rises in the core are monitored and recorded while the existence of hot spots is investigated with infrared monitoring equipment (and possibly a nonreflecting mirror) (Figs.11.14 to 11.16).

The temperature rises of the “good” core areas (ambient core temperature rise) are then compared to the temperature rise profile of any defective locations found. Once the defects are located and characterized, repair solutions can then be addressed.

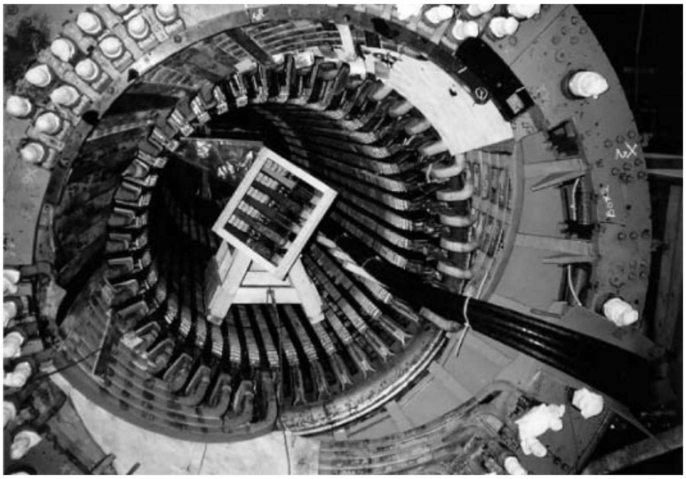


Fig. 11.13 Stator core excitation setup for a flux test of a large turbogenerator stator core, with nonreflecting mirror for infrared applications.

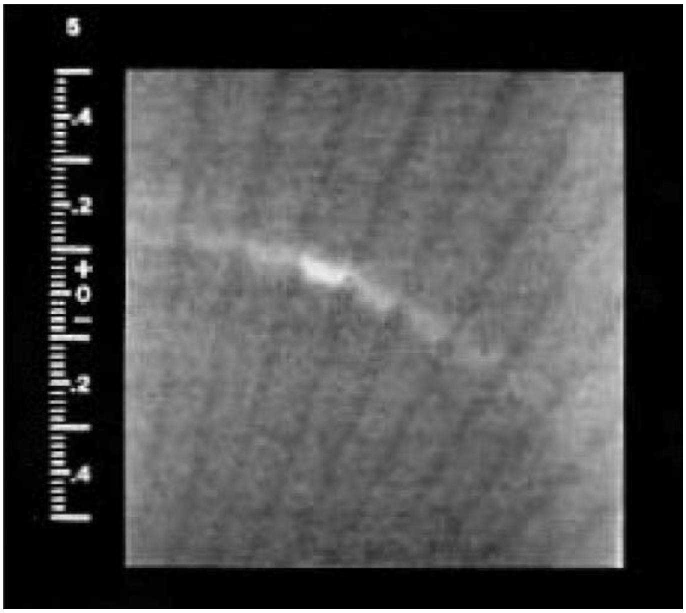


Fig. 11.14 Flux testing with direct infrared scanning of a core hot spot in the stator bore.

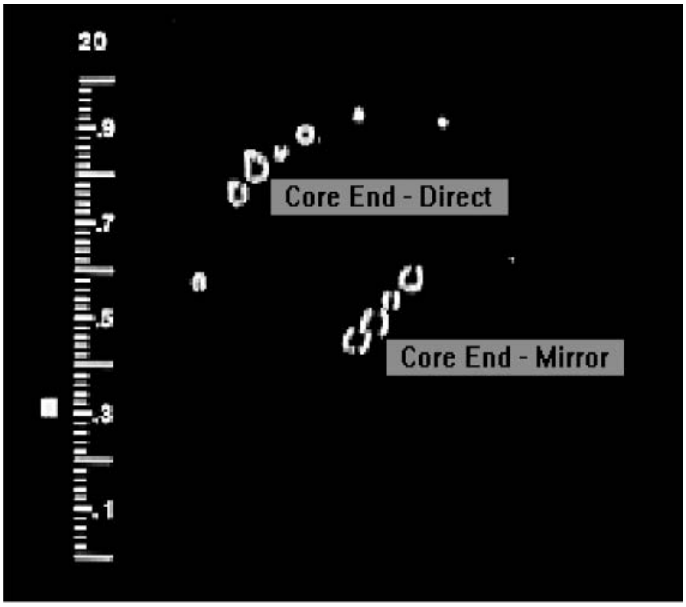


Fig. 11.15 Four core-end hot spots as seen in the non-reflecting mirror and directly, using an isotherm level to measure the temperature of the defects.

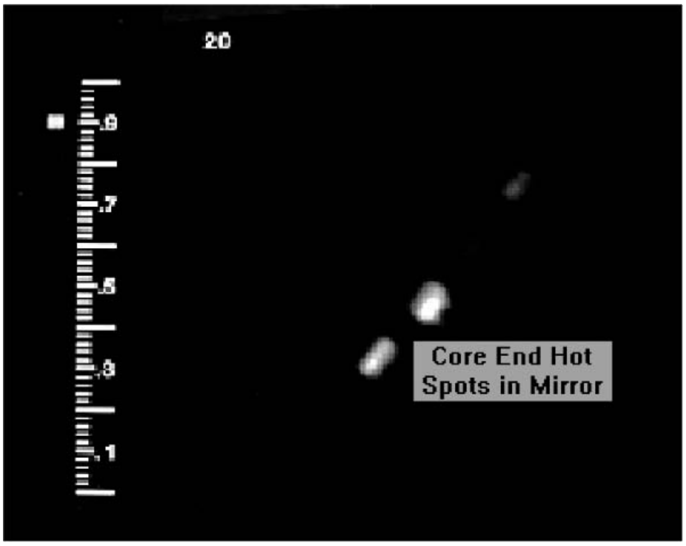


Fig.11.16 Same core-end hot spots seen by zooming in with the infrared camera on the nonreflecting mirror.

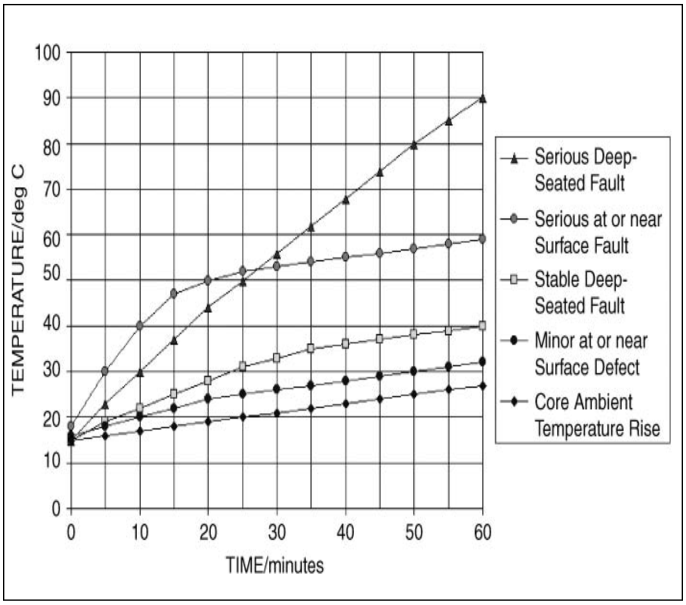


Fig. 11.17 Temperature rise profiles of typical core fault types during flux testing with infrared scanning.

11.2.3 CORE LOSS TEST

Stator core loss is a function of terminal voltage. The open circuit saturation curve for the core iron determines it. The core loss for any particular generator is always determined at the factory by the manufacturer, and is not a test that is generally done at site.

The core loss is determined by the generator being coupled to, and driven by, a calibrated motor. The friction and windage (mechanical) losses are calculated and separated out from the electrical losses to provide a value of core loss for the stator [7].

If there is suspected wear of the inter-laminar insulation in the core, on a large scale, it may be possible that a core loss test could be done to compare the present value to the "as new" value to determine the extent of deterioration occurring. However, the serious challenge of driving the generator at site with a calibrated motor, for all practical purposes, limits this test to the OEM's factory.

11.2.4 THROUGH-BOLT INSULATION RESISTANCE

There are a few manufacturers that provide through-bolts in their stators to pull the cores tight. These through-bolts are full-length bolts inserted axially through the core through holes in the core iron. There are many of them located symmetrically around the circumference of the core, a few inches below the stator winding slots. The ends are threaded and terminated at each end through a pressure plate, where a nut is installed to maintain compression after the core is pressed to a few hundred psi.

The entire through-bolt assembly is insulated generally by cured epoxy/glass tape wrap or a phenolic tube through the core, and an arrangement of insulators at the pressure plates and nuts. This is done to ensure that the through-bolts do not create any short circuits across the stator core laminations and cause a core failure by circulating currents.

To ensure that the insulation is in good condition, the insulation resistance of the through-bolts is checked by meggering at 500 V DC. A good reading should be in the hundreds of MO range.

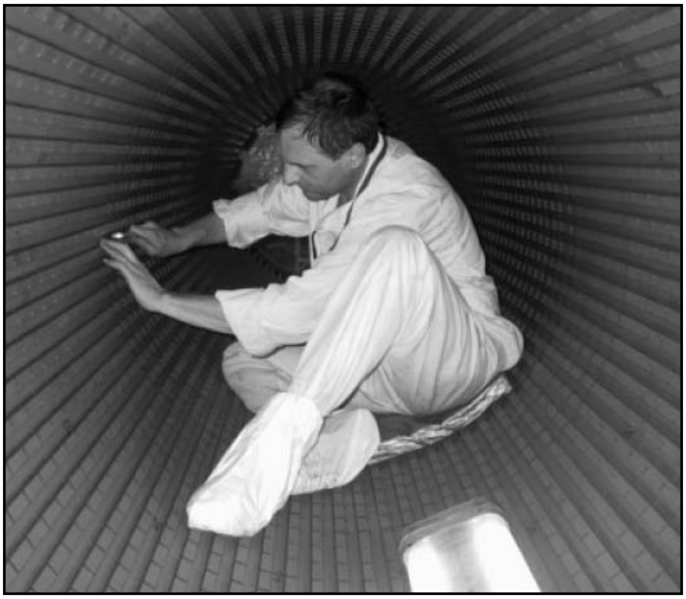
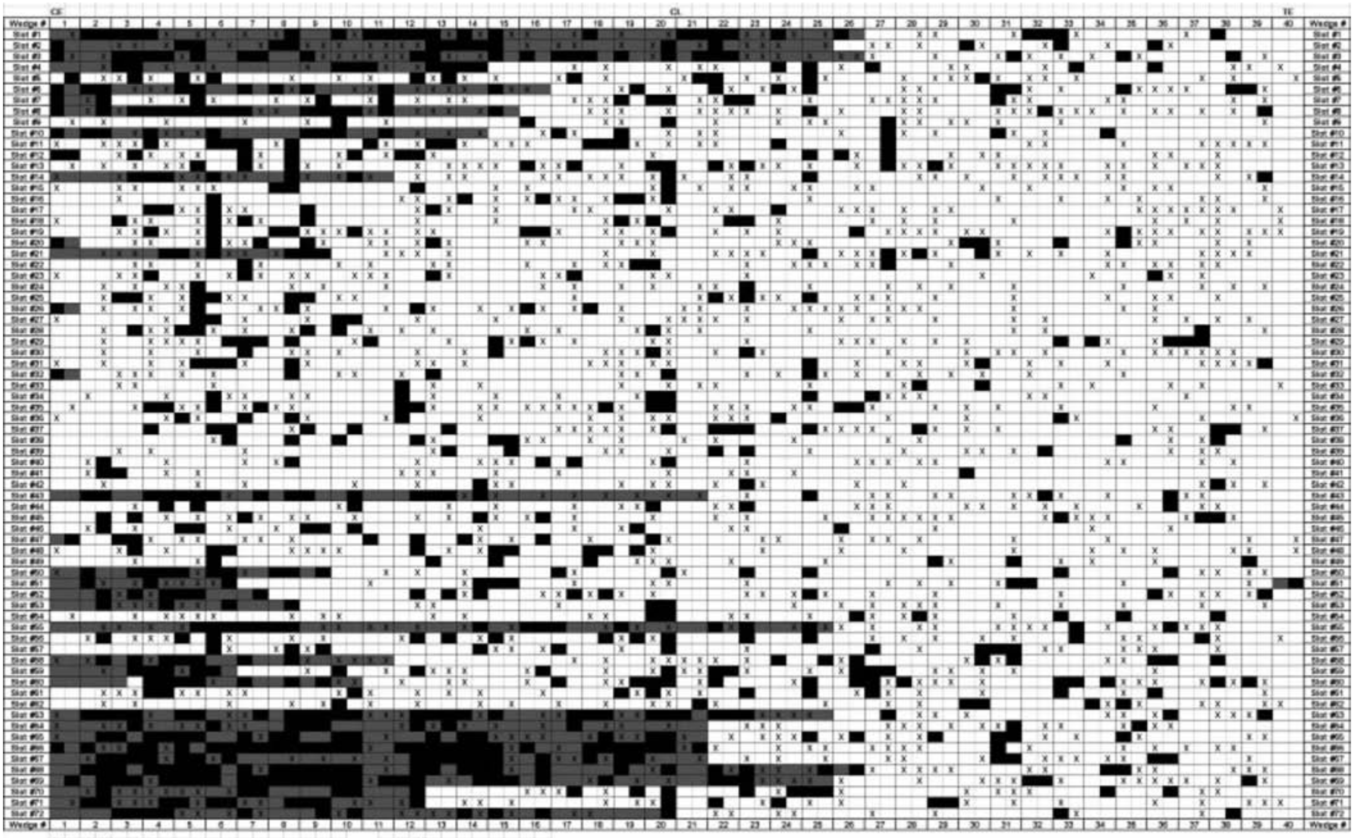


Fig. 11.18 Stator winding wedge tightness testing by manual tapping method.

11.2.5 INSULATION RESISTANCE OF FLUX SCREENS

Most large generators are provided with some form of flux screening for the stator core-end. This is to prevent overheating in the core ends due to stray flux from the stator end winding. When flux screens are used, they are insulated from the core end to ensure that no additional circulating currents flow between the core and the flux screens, which would create additional unwanted heating in the core-end.

To ensure that the insulation is in good condition, the



Wedge Tightness Summary

■	Loose	>	820	=	14.2	%
X	Medium	>	1574	=	27.3	%
	Tight	>	3366	=	58.5	%
	Total	>	5760	=	100	%
▨	Wedges Recommended to be Re-tightened					

> 72 Slots
> 40 Wedges per slot
> tap each wedge on each end
> 72 x 40 x 2 = 5760 samples
CE > Collector End
CL > Centre Line
TE > Turbine End

Fig. 11.19 Real example of a stator-winding wedge-tightness survey map showing tight, medium, and loose wedges. Also the dark areas of loose wedges are shadowed over where re-wedging during an outage was recommended and carried out.

insulation resistance of the flux screens is checked by meggering at 500 V DC. A good reading should be in the hundreds of mega-ohms range.

11.3 STATOR WINDING MECHANICAL TESTS

11.3.1 WEDGE TIGHTNESS

Loose stator winding wedges allow the stator winding in the core slots to move because of electromagnetic bar bounce forces and vibration. This can in turn cause the ground-wall insulation of the winding to wear and fret against the stator core iron and eventually fail by ground fault. Therefore it is necessary to maintain the stator winding wedges tight to avoid such problems.

Checking wedge tightness is done by tapping with a suitable hammer (i.e., an 8 oz ball peen) and recording the degree of looseness on a chart (Figs. 11.18 and 11.19). During the tapping, the wedge should be checked by tapping along its full length and feeling for the vibration as well as listening to the sound produced. Tight wedges will have very little vibration and a hard ringing sound. Loose wedges will noticeably vibrate and have a very hollow sound. Wedges with vibrations and sounds in between these indicate that the wedge is in the process of becoming loose. It requires a trained ear and feel to determine the degree of looseness in wedges of various machines because not all wedging systems are alike and they do not all sound and feel the same.

The criteria for determining when re-wedging is required is well established, with some variation from one manufacturer to another, and from one operator to another. However, the following is the accepted rule-of-thumb.

Re-wedging in a particular slot is required if:

1. Less than 75% of the wedges are tight in the slot
2. Three or more adjacent wedges are fully loose
3. Fully loose end-wedges must be re-tightened.

Since the early 1980s there have also been automated systems developed for wedge-tightness testing. Such devices mechanically stimulate the wedge being tested and record the vibration produced from it. With some modern devices (Fig. 11.20), the vibration results are input to a computer and a map is produced.

Once a wedge-tightness survey is performed, it is always a good practice to record the tightness for successive surveys of the machine, so that an estimate can be made of when tightening should be done. The individual surveys of a machine should also be compared to other identical machines in a multi-unit station, since they do not always loosen at the same rate. This can be seen in an actual example shown in Figure 11.21, taken from a four-unit station with identical machines, where three of four generators tended to loosen at the same rate while one loosened much quicker.

11.3.2 STATOR END-WINDING VIBRATION

High vibration on the stator end-winding can cause premature winding failures.

Acceptable vibration limits may vary from one manufacturer to another. Generally, however, a good rule is to keep the maximum vibration to less than 50 ºm (~2 mil) peak to peak (unfiltered), with no natural resonance within the frequency ranges 50-75 Hz and 100-140 Hz for 60 Hz units or about 40-65 Hz and 80-120 Hz for 50 Hz units (similar to the stator core and frame limits). When in doubt, it is best to contact the OEM for a recommendation on vibration limits.

Measurements are accomplished by vibration transducers mounted on the coil heads or stator bar connections at each end of the machine. Mounting is done in such a way that the transducers are insulated from, and noninvasive to, the electrical circuit of the winding. The transducers should be capable of radial and tangential vibration measurements.

If permanent mounting is not possibl, another method is to carry out an impact frequency spectrum analysis of the end-winding. This is done with temporary vibration transducers mounted on the end-winding and a calibrated impact hammer to measure the vibration signatures.

This test is also known as a "bump" test.

As in the stator core and frame, end-winding vibration problems are very difficult to diagnose and expensive to fix. They should also be addressed on a machine-to-machine basis, as each case will present a unique situation.

11.4 WATER-COOLED STATOR WINDING TESTS

11.4.1 AIR PRESSURE DECAY

The pressure decay test is probably the oldest test method for detecting leaks. The stator winding is first completely dried out internally, and then pressurized up to the level of the generator operating hydrogen gas pressure. This provides a very high pressure differential and a leak direction that is normal to the

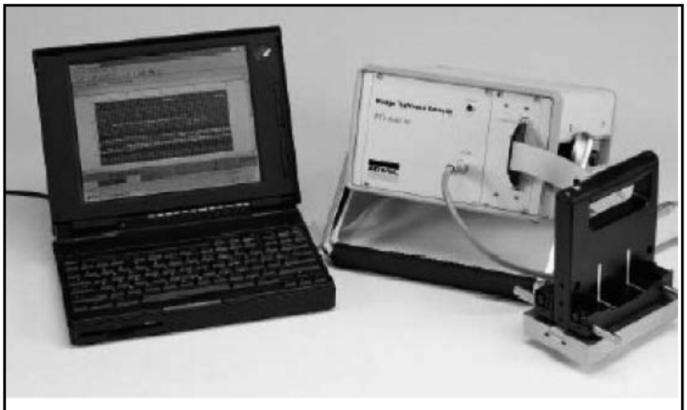


Fig. 11.20 Automated testing and mapping system. (Courtesy of ADWEL International

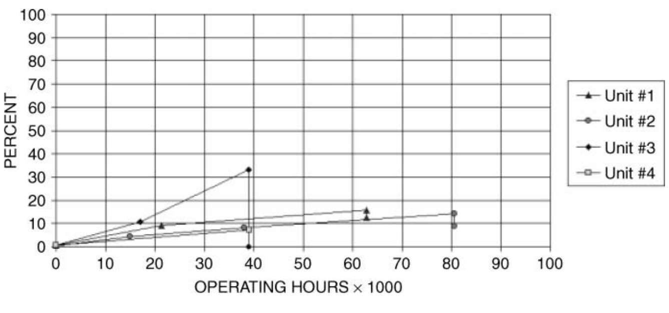


Fig. 11.21 Stator-winding wedge-looseness profile record over time. This shows the difference between four supposedly identical machines and that they do not necessarily loosen at the same rate.

operating leak direction.

When pressurized to levels as high as the operating hydrogen gas pressure, a 1 psi pressure drop will only correspond to about 1 cu ft loss of volume. This test is therefore not sensitive to small leaks and highly dependent on atmospheric conditions of temperature and barometric pressure. It is carried out by pressurizing the stator winding to about 30 psi and watching that the drop in pressure over a 6 hour period does not exceed 0.1 psi. To recognize smaller leaks, the test must be carried out over a period as long as 24 hours using very accurate and calibrated pressure gauges.

During pressurization, "snooping" is also used to identify leaks. This technique entails application of a soapy water solution to the winding in selected areas. It is generally used at joints, fittings, and points that are likely sources of leaks.

If a leak is present, the soapy water will bubble indicating that the tracer gas is escaping at the bubble location.

Another method of detecting leaks is to use an ultrasonic probe to listen for the sound created by the leaks (Fig. 11.22).

11.4.2 TRACER GASES

Freon gas was, at one time, the preferred gas for leak tracing and snooping. Due to environmental factors, Freon has been superseded by the use of helium gas.

Helium is a light gas, which is molecularly small in size making it ideal for this application. In addition, it is nontoxic and non-hazardous.

The trace method involves pressurizing the stator winding with helium, or a mixture of air and helium. A portable helium gas detector is then used to "sniff" over the external surfaces of the exposed portions of the stator winding for sources of helium. Obviously this method requires access to the generator internals, and even so, it is still not possible to cover the entire winding by this method. Therefore it is only one of the tests that are required to fully identify leak problems and locate the source.

The helium tracer technique has been shown to be very successful in pinpointing stator winding leaks.

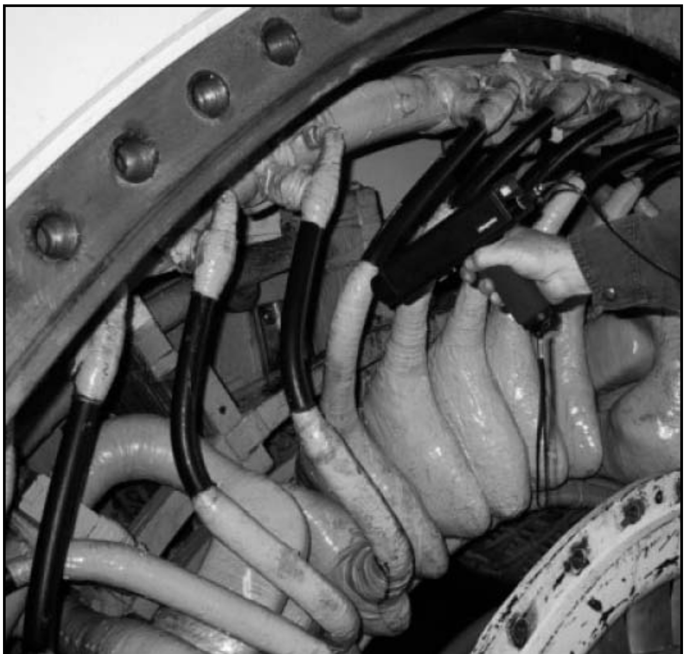


Fig. 11.22 Ultrasonic probe used to detect sound from air pressure test leaks.

11.4.3 VACUUM DECAY

Vacuum decay testing is very sensitive compared to pressure decay testing. It is generally used to determine the leak sensitivity of the entire winding. This test has the advantage that it is relatively insensitive to atmospheric conditions of temperature and to barometric pressure. Further it only requires a few hours on test to determine the leak rate, since vacuum gauges are far more sensitive than pressure gauges. The test leak direction is opposite to the operating leak direction of water but normal to the operating leak direction of hydrogen into stator cooling water (SCW). Even the smallest leaks will be detected by this method. The test is carried out by pulling vacuum to 29 inches of mercury, and watching that the vacuum gauge does not drop in vacuum by more than 0.2 inches Hg over 6 hours.

11.4.4 PRESSURE DROP

The differential pressure across the stator winding from the stator cooling water inlet to the outlet of the generator can also be tested in the off-line mode to ensure that the design pressure drop across the whole stator winding is at the correct level. Alternatively, each individual stator bar can be pressure-drop tested to estimate the stator cooling water flow rate in each bar, and ensure that it is above the minimum recommended level for adequate cooling of the stator winding.

11.4.5 FLOW TESTING

Flow checks are generally done on individual bars to determine if there are restrictions in the cooling water path. Both air and water have been used to accommodate this test, but it is usually done with water. The actual flow in each stator bar is measured to compare it to the design level of flow required for the particular machine being tested. Some flow checks are made using ultrasound techniques to monitor the flow rates. Low flow bars are then noted for corrective action such as backflushing or chemical flushing.

11.4.6 CAPACITANCE MAPPING

Capacitance mapping is a nondestructive electrical test method used to identify the presence of moisture in the groundwall insulation from stator winding leaks.

The technique is based on the difference in dielectric constant of the ground-wall insulation and that of water. All top and bottom bars are tested at both ends of the machine, providing an average measurement of capacitance. The measurement is made by a capacitance probe placed on the side of each bar. Good insulation is indicated by measurements falling within ±2 standard deviations from the average. Measurements of capacitance greater than +3 standard deviations are considered suspect, and those greater than +5 are generally found to be wet and to fail their subsequent electrical tests. Failure of this test tends to indicate that the stator bar is not suitable for long-term service.

Care must be taken when performing this test, since the capacitance measurements are also sensitive to the application of the capacitance probe, bar surface condition and coatings, grading paints, and the condition of the ground-wall insulation itself.

11.5 STATOR WINDING ELECTRICAL TESTS

Stator windings are comprised of materials with specific resistive and dielectric qualities. The materials used comprise: mica, Dacron tapes, glass tapes, asphalt binders, polyester resins and epoxy resin binders, and so on. There are also insulating, resistive, and stress grading paints applied to various portions of the winding to ensure controlled distribution of the voltage on the individual stator conductor bars. All of the materials used, and their application, are done in such a manner as to ensure proper functioning and a reasonable degree of long term reliability of the winding. The stator winding insulation system is complex and requires a variety of tests to establish its present condition and expected long-term reliability. Therefore, to fully test the stator winding, so that the best possible determination of the winding condition can be made, it is desirable to perform both AC and DC tests.

The DC tests are generally sensitive to the presence of cracks, moisture, particle contamination, or a general degradation of the electrical creepage path. During DC application, the voltage is divided according to the DC leakage resistance.

Basically, DC is used to test the conductivity of the insulation system. The DC testing has the advantage that it less damaging to the insulation due to the absence of corona and partial discharges associated with AC.

The AC testing, on the other hand, applies the more realistic electrical stress to the winding, since it operates ac when in service. When the AC test voltage is applied, it is actually applied across several dielectric components of the winding insulation, which are effectively in series. Therefore, the leakage current must go through each of the dielectrics until it reaches ground potential. Under AC, the voltage is therefore divided according to the relative permittivity of each of the dielectric materials.

The AC testing is in fact far more searching than DC. In addition to the conducting properties of the insulation, AC testing is also capable of determining the loss or power factor characteristics and the dielectric properties. In addition the mechanical integrity of the insulation can be also be alluded to by the capacitance characteristics of the winding in terms of insulation de-lamination.

As with many other issues about testing insulation of large electric machines, experts and operators have different opinions about which one of the two tests (DC and/or AC) is more convenient. Some only prefer DC tests, while other prefer AC testing. Still, others like to use both.

11.5.1 PRE-TESTING REQUIREMENTS

If the stator winding is water cooled, it must be completely dried prior to all testing to obtain meaningful results. If there is stator cooling water left in the winding, it will alter the test results and give a distorted picture of the insulation condition.

All three phases must be isolated to ensure that all testing is carried out on the stator winding only. This means that each phase should be completely separated at the neutral point and floated from ground. The line ends of the stator winding should be separated from the isolated phase bus (or cables, in smaller units) just outside the generator, at the stator terminals.

The generator current transformer windings should be shorted and grounded to avoid induced high voltage and possible discharge failure of the insulation.

All instrumentation leads should be grounded to also avoid induced high voltage and possible discharge failure of the insulation.

Before conducting any high-voltage testing of the unit, consult vendor and/or pertinent standards.

11.5.2 SERIES WINDING RESISTANCE

This test is used to measure the ohms resistance of the copper in each phase of the stator winding. Given the relatively low DC series resistance of windings of large machines, the measurement accuracy requires significance to a minimum of four decimal places.

The purpose of the test is to detect shorted turns, bad connections, wrong connections, and open circuits. Acceptable test results consist of the three resistance values (one per phase) to be balanced within a 0.5% error from the average.

The test is very sensitive to differentials of temperature between sections of the winding. The machine should be at room temperature when the test is performed.

As with any other electrical test, the results should be compared with original factory data, if available. This test can be performed on stator and rotor windings.

11.5.3 Insulation Resistance (IR)

The purpose of this test is to measure the ohmic resistance between the conductors in each of the three-phases and ground (i.e., the stator core). This test is generally regarded as an initial test to look for gross problems with the insulation system, and to ensure further high-voltage electrical testing may “relatively” safely continue, in terms of danger of failing the insulation.

Normally the measurements of IR will be in the megaohm range for good insulation, after the winding is subjected to a DC test voltage usually done anywhere from 500 to 5000 V, for one minute. The minimum acceptable reading by IEEE Standard 43 [4] is (VLL in kV + 1) M©. The test is carried out with a megger device. However, resistance bridges may also be employed.

The DC test voltage level is usually specified based on the operating voltage range of the machine, the particular component of the generator being tested, operator's policy and previous experience, and knowledge of the present condition of the insulation in the machine. Although the readings obtained will be somewhat voltage-dependent, this dependency becomes insignificant for machines in which the insulation is dry and in good condition. It is essential that water-cooled stator winding be completely dried before any testing so that any poor readings will be due to a “real” problem, and not to residual moisture from the stator cooling water.

The readings are also sensitive to factors like humidity, surface contamination of the coils, and temperature. Readings should be corrected to a base temperature of 40°C by the following:

$$R\ (40^{\circ}\mathrm{C}) = K \times R_{\mathrm{measured}}(^{\circ}\mathrm{C})$$

Insulation resistance tests are performed on both stator and rotor windings, core endflux screens, and core compression or through-bolts as mentioned previously.

The insulation between the core-end flux screen and the stator core-end iron ensures that the flux screen maintains its capability to shield the core-end from axial flux, and keep the resulting circulating currents within the flux screen, without providing a current path to the core.

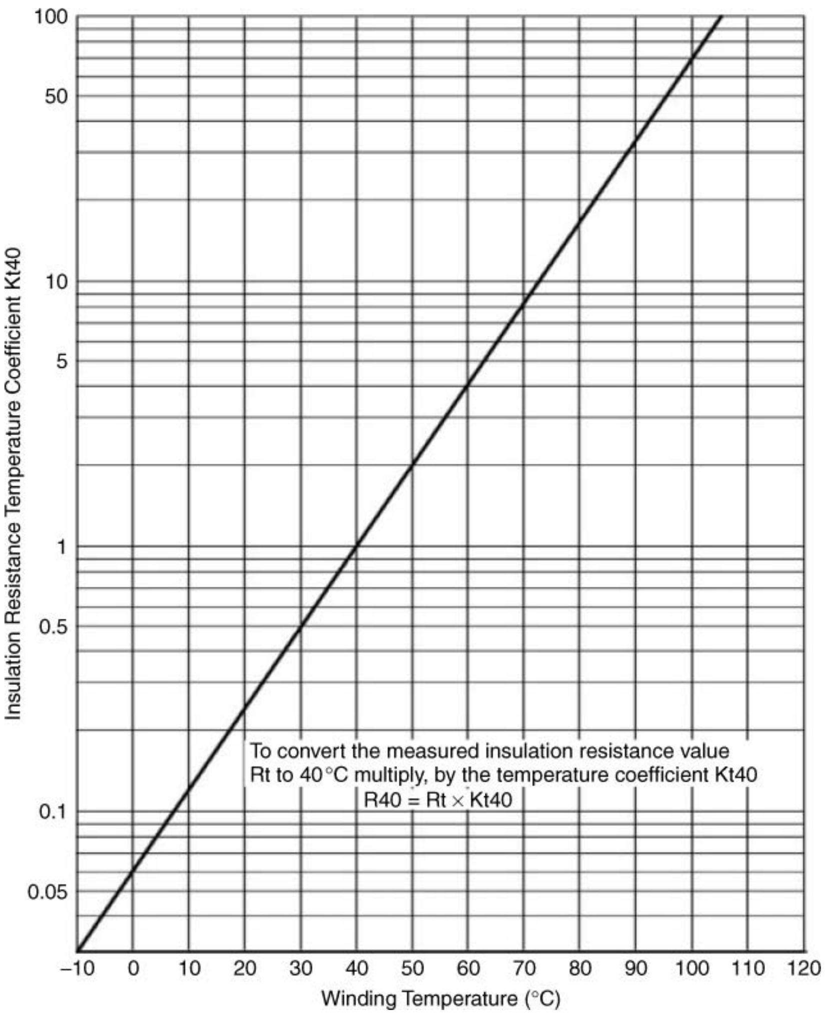


Fig. 11.23 Insulation resistance versus winding temperature curve. (Courtesy of EPRI).

The insulation between core-compression bolts and the iron keeps the throughbolts from short-circulating the insulation between the core laminations. Otherwise, large eddy currents generated within the core would produce heat and temperatures, which could further damage the inter-laminar insulation, as well as the insulation of the windings. Figure 11.24 shows typical IR behavior as a function of time.

11.5.4 POLARIZATION INDEX (PI)

Insulation resistance is time-dependent as well as being a function of dryness.

The amount of change in the IR measured during the first few minutes depends on the insulation condition, and the amount of contamination and moisture present.

Therefore, when the insulation system is clean and dry, the IR value tends to increase as the charge is absorbed by the dielectric material in the insulation.

When the insulation is dirty, wet or a gross insulation problem is present, the charge does not hold, and the IR value will not increase because of constant leakage current at the problem area. Therefore the ratio between the resistance reading at 10 minutes and the reading at 1 minute produces a number or "polarization index" which is essentially used to determine how clean and dry the winding is (Fig. 11.25).

Class B and F windings tend to show higher PI values than windings made of class A insulation. It is also dependent on the existence of a semiconducting layer.

$$K = 0.0635 \times \exp(0.06895 \times T_{\text{measurement}}(\text{in }^\circ\text{C})$$

The recommended minimum PI values are as follows:

Class A insulation: 1.5
Class B insulation: 2.0
Class F insulation: 2.0

The same megger used for the IR readings should be used to determine the PI. The PI readings should be done on a per phase basis at the same voltage as the IR test, and can be used as a go/no-go test before subjecting the machine to subsequent high voltage tests, either AC or DC. The IR readings for the PI test should also be corrected to 40°C as in the IR test. Performing the high-voltage tests on wet insulation may result in unnecessary failure of the insulation.

11.5.5 DIELECTRIC ABSORPTION DURING DC VOLTAGE APPLICATION

Dielectric absorption current characteristics can be used to measure the aging of the resin binder in the ground-wall insulation. When applying DC voltage to insulation material, a time-dependent flow of current is established. This current has a constant component, called the conduction current or leakage current, and a transient component, called the absorption current.

Absorption current is a function of the polarization of the molecules in the binding

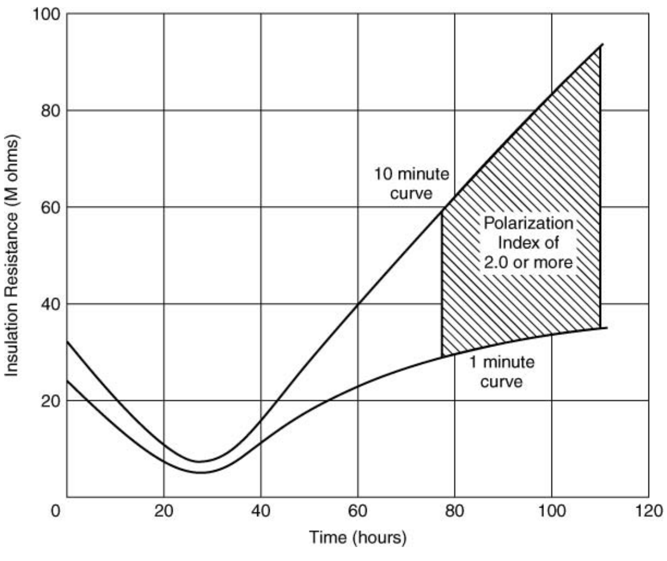


Fig. 11.24 Insulation resistance as a function of time and dryness. (Courtesy of EPRI).

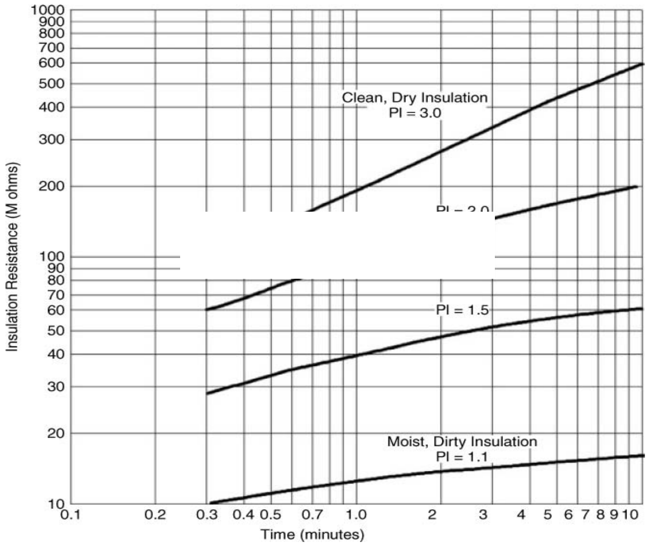


Fig. 11.25 Polarization Index curves for insulation resistance as a function of time. (Courtesy of EPRI).

material. The older the binding material, the more polarized it becomes, and the more absorption current flows. Therefore this test is best used as a comparison test between the winding condition at different times, and between similar windings.

Absorption current is also temperature dependent. This fact should be taken into consideration when performing the test and interpreting the results.

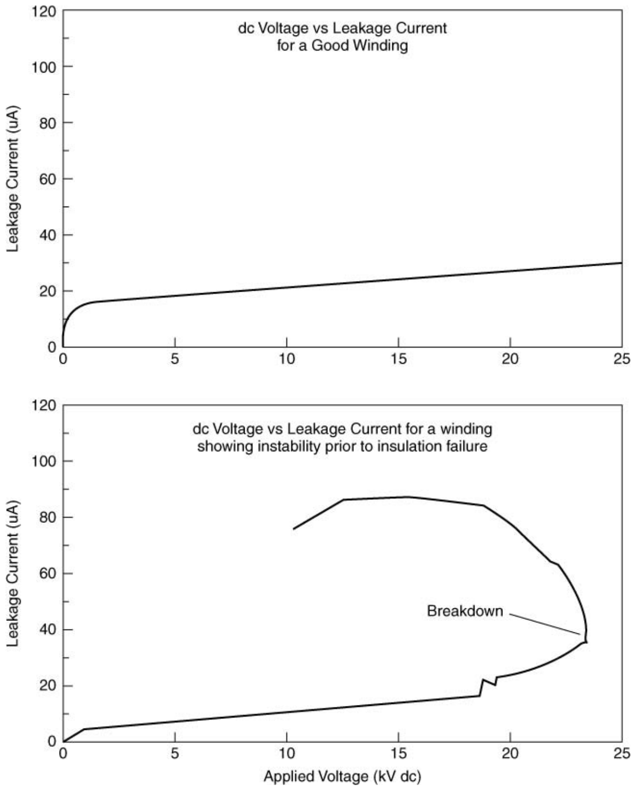


Fig. 11.26 DC Ramp test plot. (Courtesy of EPRI).

Absorption current is also dependent on the amount of voids in the insulation.

The dependence is inverse, meaning an increase in the number of voids in the insulation will tend to reduce the magnitude of absorption current. The contradictory effects regarding voids density and aging of the binding material renders this test difficult to interpretation. It is best when used in conjunction with other dielectric tests, such as partial discharge and dissipation factor tip-up tests.11.5.6 DC Leakage or Ramped Voltage

The DC leakage or ramped voltage test is a controlled DC voltage application designed to test the winding in such a manner as to monitor the DC leakage current, at the same time the DC voltage is increased. The leakage current is plotted against the DC voltage applied to give early warning of any impending insulation breakdown. This helps in limiting damage by shutting down the test prior to a full breakdown occurring (Fig. 11.26).

When DC voltage is applied to the winding, a time-dependent flow of current is established. This current has a constant component, called the conduction or leakage current, and an initial component, called the charging or absorption current.

Therefore it is advisable to raise the voltage to the first level of the kV/min rate, hold for 10 minutes to get beyond the charging phase of the voltage application, and test while dealing primarily with the leakage current. This way the charging current influence on the leakage current rate of rise will be minimized.

The final DC test voltage level is generally in the range of 125 to 150% of (VLL °- 1.7) kV dc (ANSI Std C50.10). The value actually chosen between 125% up to 150% of the test voltage is dependent on the age of the machine insulation, and knowledge of its general condition.

The ramp rate is selected at 3% of the final test voltage level in kV /DC/minute (IEEE Std 95). The ramp rate usually is in the range of 1.5 to 2 KV per minute.

Generally, the ramping portion of the test is automated to allow a steady increase in the voltage. A DC hi-pot set with the capability of a timed and steady voltage increase is required. If this is not possible with the equipment available, then a basic DC hi-pot set can be used to raise the voltage in the pre-determined 3% voltage steps, holding each step for 1 minute.

11.5.7 DC HI-POT

The DC hi-pot test is used to ascertain if the winding is capable of sustaining the required rated voltage levels (without a breakdown of the insulation), with a reasonable degree of assurance for capability to withstand overvoltages and transients, and maintain an acceptable insulation life. The test consists of applying high voltage to the winding (the three phases together, or one at a time, with the other two grounded) for one minute.

The recommended test voltage level is [(2 °- VLL + 1000) °- 1.7] kV DC for new windings (ANSI Std C50.10). The recommended test voltage level for field testing and maintenance purposes is 125 to 150% of (VLL °- 1.7) kV dc (ANSI Std C50.10). The value actually chosen for the test voltage is dependent on the age of the machine insulation, knowledge of its general condition, and the specific situation calling for a test.

11.5.8 AC HI-POT

The AC hi-pot test is also used to ascertain if the winding is capable of sustaining the required rated voltage levels (with-

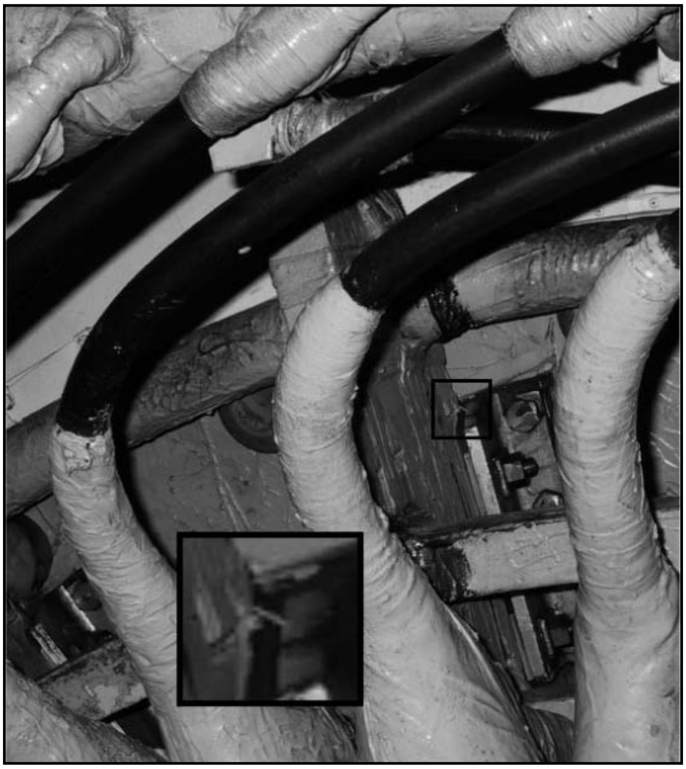


Fig. 11.27 Arcing occurring between a phase connector and ground during an AC hi-pot test.

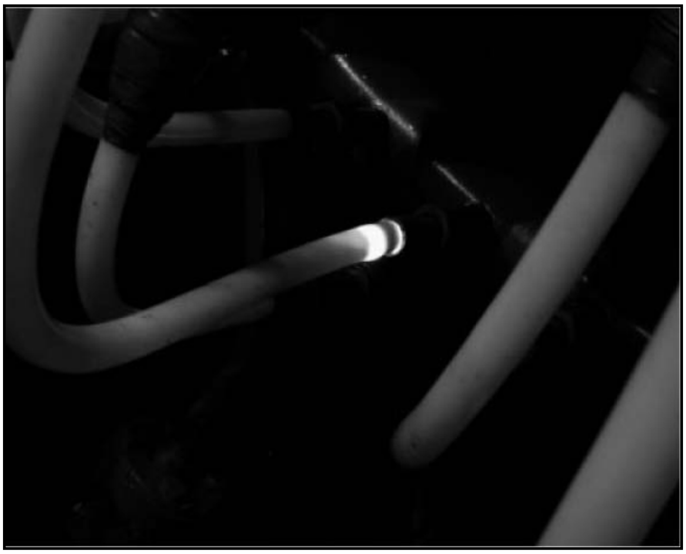


Fig. 11.28 Glowing hoses during a "wet" AC hi-pot test where contamination of the hoses is present.

out a breakdown of the insulation), with a reasonable degree of assurance for capability to withstand overvoltages and transients, and maintain an acceptable insulation life. The test consists of applying high voltage to the winding (the three phases together, or one at a time, with the other two grounded) for one minute.

The recommended test voltage level is (2 °- VLL + 1000) kV AC for new windings (ANSI Std C50.10). The recommended test voltage level for field-testing and maintenance purposes is 125 to 150% of VLL kV ac (ANSI Std C50.10). The value actually chosen for the test voltage is dependent on the age of the machine insulation, knowledge of its general condition, and the specific reasons for the calling for a test.

The AC testing is generally done at power frequency of 60 Hz but may also be carried out at a low frequency of 0.1 Hz, which is the accepted industry standard.

Generally, the AC hi-pot is a "pass" or "fail" type of test. However, this is not always the case. There are often times when arcing can be heard and even seen (Fig. 11.27), and the test can be stopped until the problem area is repaired. Then retesting may be carried out to prove the repairs.

Also, testing is usually done on water-cooled windings with the system drained and vacuum dried before voltage application. However, there are instances where good DC measurements have been recorded on two phases while one appears grounded, and the winding is technically "wet". In such an instance, AC testing has been done as a next step, but this is a rare occasion. It is not recommended to proceed with this type of testing unless an expert is present who knows how to handle this type of situation. One reason to do a "wet" AC test is when no failure point can be found, and yet the winding will not hold DC voltage and internal contamination of the stator winding hoses is suspected. Under dry conditions, the winding will pass high-voltage testing, and under wet conditions, the contamination will be conducting. Depending on the type of contamination and its conductivity, the hoses may glow under high voltage AC (Fig. 11.28).

11.5.9 PARTIAL DISCHARGE (PD) OFF-LINE TESTING

In principle, PD measurements are based on direct measurement of the pulses of high-frequency current discharges created during the occurrence of partial discharges. Some off-line methods are based in a capacitive link between the whole of the winding and the measurement equipment. These setups allow the measurement of PD activity in whole windings, or one phase at a time.

To measure the PD activity in smaller sections of the winding, methods based on an electromagnetic probe or pickup (which is mounted on a hand-held electrically insulated stick) has been developed. One such probe is known as the TVA probe and is used to traverse the entire length of a slot in the stator bore to search for localized sources of PD. Therefore each slot is probed over its full length.

The partial discharge tests are carried out from voltages below the inception voltage up to rated voltage.

On-line partial discharge analysis can be performed by modern instrumentation and methods described in the following sections.

PD Monitoring by Capacitive Coupling. Partial discharge monitoring by capacitive coupling is generally an on-line test nowadays, but off-line measurements are also done on a regular basis. The test setup for off-line capacitive coupling is generally as shown in Figure 11.29.

During operation of a generator, the voltage on the stator winding is graded according to the line to neutral connection. Thus, when an on-line test is performed, the bars near the neutral end of the machine are not subjected to high voltage, which represents the actual operating condition. In the off-line test, all stator bars are energized to the level of the test voltage applied, and therefore all may show PD activity. However, in the off-line test, the effects of vibration and bar forces are not in play. These issues are important to be taken into consideration when analyzing the test results, and their implication on the condition of the unit.

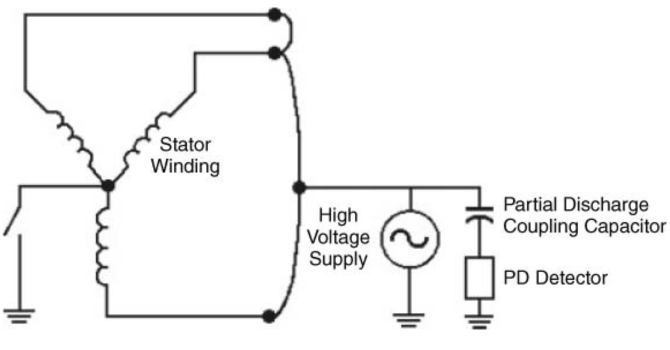


Fig. 11.29 PD testing by capacitive coupling, off line. (Courtesy of EPRI).

PD Monitoring by Stator Slot Coupler

The stator slot coupler (SSC) is basically a tuned antenna with two ports. The antenna is approximately 18 inches (46 cm) long and is embedded in an epoxy/glass laminate with no conducting surfaces exposed. SSCs are installed under the stator wedges at the line ends of the stator winding, such that the highest voltage bars are monitored for best PD detection. Since the SSC is also installed lengthwise in the slot at the core end, its two port characteristic gives it inherent directional capability.

The problem of noise is virtually eliminated in the SSC. Although the SSC has a very wide frequency response characteristic that allows it to see almost any signal present in the slot where it is installed, it also has the characteristic of showing the true pulse shape of these signals. This gives it a distinct advantage over other methods, which cannot capture the actual nature of the PD pulses. Since PD pulses occur in the 1 to 5 nanoseconds range and are very distinguishable with the SSC, the level of PD activity can be more closely defined.

In addition, dedicated monitoring devices have been devised to measure the PD activity detected in the SSC. The capability for PD detection using the SSC and its associated monitoring interface is enhanced to include measurement in terms of the positive and negative characteristic of the pulses, the number of the pulses, the magnitude of the pulses, the phase relation of the pulses and the direction of the pulses (i.e., now from the slot or from the endwinding or actually under the SSC itself at the end of the slot).

The other advantage of the SSC is that once it is installed, measurements may be taken at any time without the need for exposing live portions of the generator bus-work, for the purpose of making connections to the test equipment.

Corona Probing for PD. Partial discharge tests in general determine only the relative condition of the stator winding from the generator terminals. They do not locate specific sites of deterioration or damage in the winding. To do this, the winding must be locally scanned with special probes designed to detect localized sources of PD, while the winding is energized to the level of line-to-neutral voltage. There are a couple of variations of probe types, one based on radio-frequency noise and the other on acoustical noise. (SSCs do provide some information about the location of the PD activity. The more SSCs installed in a particular winding, the higher the accuracy in determining the location of the offending bar.)

The "TVA probe" gets its name from the Tennessee Valley Authority where it was first popularized. It is based on an earlier Westinghouse probe design that was sensitive to RF signals produced by PD in the winding. It functions by picking up the RF energy radiated from active PD sites in the winding.

The greater the PD, the greater the RF energy produced. The tip of the TVA probe employs a loop antenna similar to that used in an AM radio. The TVA antenna is tuned to about 5 MHz so that it is sensitive to near-field RF discharge.

The output of the antenna is directed by a co-axial cable to a tuned RF amplifier and a peak-reading ammeter that is sensitive to peak PD pulses. The closer the antenna is brought to an RF (or PD) source, the higher the output on the meter.

The "ultrasonic probe" functions based on acoustic noise produced by localized PD sites. The noise is similar to a crackling sound that one might hear when next to a high-voltage overhead transmission line on a wet day. This noise is loudest in the ultrasonic frequency range around 40 kHz. A high directional microphone, sensitive to the 40 kHz noise, is used to locate the site of the PD discharges.

Given that ultrasonic noise does not easily penetrate insulation, the ultrasonic probe test is primarily sensitive to surface PD, namely the sites of slot discharge and surface endwinding PD. See Figure 11.22

11.5.10 CAPACITANCE MEASUREMENTS

Capacitance measurements are also a method of measurement by which the quality of the insulation can be indicated. The measurements are, of course, done with AC voltage, and generally on a per phase basis.

Each phase of the stator winding is energized to line-to-neutral voltage, while the other two phases are grounded. The power factor of the winding is measured with a capacitance bridge to determine the value of the per-phase winding capacitance.

Comparison of the measured capacitance to the factory measured values, and then successive capacitance readings, can aid in showing deterioration of the ground-wall insulation over time.

11.5.11 DISSIPATION/POWER FACTOR TESTING

The dissipation factor (or tan ¥) is an AC test used to measure the bulk quality of the ground-wall insulation, by measuring the dielectric loss (primarily due to partial discharges) per unit of volume of the insulation. Note:

$$\text{(Dissipation factor) DF} = \tan\delta$$

$$\text{(Insulation power factor) IPF} = \frac{\text{DF}}{\sqrt{1+(\text{DF})^2}} = \sin\delta$$

Results are generally dependent on the type of the dielectric material in the insulation system. An increase in DF over the life of the winding can be attributed to an increase in internal voids, de-laminations, and/or increased slot-coil contact resistance (i.e. deterioration of the semi-conducting paint in the slot).

The readings are a dimensionless quantity expressed as a percentage. The absolute values obtained are, again, a function of the type of insulation system being measured and are also directly affected by the temperature of the winding.

Therefore it is important that insulation power factor readings be taken at similar temperatures. The results are even

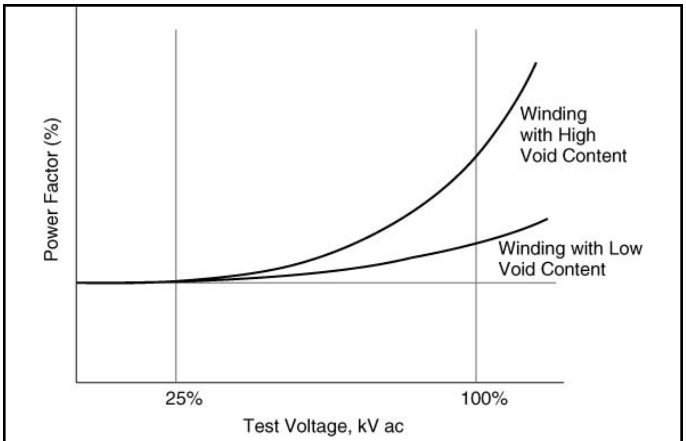


Fig. 11.30 Dissipation factor tip-up test profile comparison for good and poor results.

more useful, however, in relative terms by comparison of present readings to past readings. Successive measurements provide a scale of the deterioration rate of the insulation system over time.

Therefore, when using dissipation factor as a function of time, it is important to maintain constant conditions during testing. The DF readings are directly affected by the temperature of the winding and are also a function of the applied voltage.

Therefore comparisons with previous readings should be made on tests done at similar temperatures and the same voltage levels.

Since dissipation factor readings are somewhat void dependent, the dissipation/insulation power factor ratio will increase with an increase in the amount of voids present in the insulation. This phenomenon is the base of the DF/IPF tip-up test.

11.5.12 DISSIPATION/POWER FACTOR TIP-UP TEST

The dissipation factor tip-up or î tan ¥ test looks at the void content in the insulation.

That is to say, the dissipation factor will increase with an increase in the amount of voids or de-lamination present in the insulation. In addition it provides information on other ionizing losses in the form of partial and slot discharges.

The test is done by taking DF (or insulation power factor) measurements at different voltages. A set of readings is therefore obtained, which forms an ascending curve. A fast change of insulation power factor with increasing voltage tends to indicate a coil with many voids. The test is based on the fact that ionization, both internal and external to the insulation is voltage dependent.

The test is done generally at 25 and 100% of the rated phase to neutral voltage. The tip-up value is the DF measurement at the higher voltage, minus the DF measurement at the lower voltage (IEEE Std 286). Good readings for an epoxy/mica system, indicating minimal void content in the insulation, are typically less than 1%. Good readings for an asphalt system are generally in the 3% range (Fig. 11.30).

This test will give a good evaluation of the winding as a group. However, any bad coil that deviates greatly from the rest will not be discerned by this test. To ferret out individual bars that exhibit higher discharges, a partial discharge test is done with the addition of manual probing for the location of the discharges if high levels are found to exist.

11.6 ROTOR MECHANICAL TESTING

11.6.1 ROTOR VIBRATION

Vibration measurement is one the most important on-line measurements taken on the machine. Each manufacturer gives its own recommendations for alarm and trip.

The information in the following table is from an O&M engineering specification:

MACHINE SPEED	MAXIMUM AMPLITUDE
0-999 rpm	3 mils
1000-1499 rpm	2.5 mils
1500-2999 rpm	2 mils
3000 rpm & above	1 mil

Vibration is monitored continuously, and vibration charts are normally available at the control room. Vibration is monitored in all turbine and generator bearings.

Although vibration monitoring is generally considered an on-line monitoring function, there are many occasions where it is necessary to carry out additional and specific vibration testing. This would be to look for such problems as component rubs or rotor winding shorted turns to determine the correct course of action.

This type of detailed vibration testing is very specialized and requires additional equipment to be connected to the vibration probes installed on the generator.

The type of additional testing inferred would be to allow characterization of the vibration measurements into both magnitude and phase relation, and to allow frequency spectrum analysis during cold and hot run up to speed and run downs from speed. In addition load changes and field current changes allow the differentiation between mechanically and thermally induced vibrations.

11.6.2 ROTOR NONDESTRUCTIVE EXAMINATION INSPECTION TECHNIQUES

Non destructive examination of generator rotors is usually done to look for cracks and inclusions in highly stressed dynamic components. There are generally two types of NDE testing:

o Surface (visual, magnetic particle, liquid penetrant, andeddy current);
o Volumetric (radiographic and ultrasonic).

There are generally six different test methods:

o Visual (VI);
o Radiographic (RT);
o Magnetic particle (MPI);
o Liquid penetrant (LPI);
o Ultrasonic (UT);
o Eddy current (ECT).

Visual Inspection. Good detailed visual inspection of generator components may require any or all of the following conditions and equipment:

o Adequate lighting;
o Magnifying glass;
o Mirrors with rotating heads;
o Digital camera;
o Borescope (with video recorder);
o Feeler gauges;
o Pocket ruler;

o Straight edge;
o Magnet.

The effectiveness of visual inspection is surprisingly good if the inspector is knowledgeable and thorough. For example, surface flaws - cracks, porosity, surface finish, rusting, and corrosion - can usually be easily seen, and much can be deduced from this type of inspection. From the visual inspection, one can sometimes determine as much as needed to make the right decision on maintenance action.

The advantages of visual inspection are that it is low cost, simple, and quick.

It can be done during any type of generator work that is in progress, permitting correction of faults.

Visual inspection does, of course, have limitations. It is applicable to surface defects only and provides no permanent record, unless recorded by photographs or video.

RADIOGRAPHIC

Radiographic testing is usually done by commercial X-ray or gamma units made especially for welds, castings, and forgings. It requires film and processing of the film when completed. It is not generally done for generator components, but it can be used if there are major frame weld problems. It is based on the difference in density or discontinuities in the item being examined.

The major defects that radiography can detect are interior macroscopic flaws such as cracks, porosity, and inclusions. Poor welds can be easily seen by this method.

This technique has the advantage of being applicable to most materials and once carried out, the defect areas are recorded on film to provide a permanent record.

The difficulties with radiography are that it requires skill in getting a good angle of exposure, use of the equipment, and interpreting the indications found.

It is also somewhat hazardous to health as any radiographic method and requires safety precautions to be taken to protect the equipment operator and any personnel in the area of the testing.

MAGNETIC PARTICLE

Magnetic particle inspection for surface flaws requires no special equipment. But it does require high current application to align the magnetic powders that show any flaws that are observable. This is in the range of 200 to 20,000 amps. The magnetic powders are in dry or wet form and may be fluorescent for viewing under ultraviolet light. Pigments are often added to dry metallic powders to make them more visible (yellow, red black, or gray). In the wet method, iron particles are coated with fluorescent pigment in water or oil-based suspension. Antifreeze may be added to water-based solutions to impede particle mobility.

Magnetization is done by passing current through a multi-turned coil, looped through or around the part to be examined, with no electrical contact. The magnetization field is parallel to the axis of coil-longitudinal magnetization. The flux density is proportional to the current times the number of turns in the coil.

With more turns, less current is required. A flux density of 1 tesla is satisfactory for most generator applications. Defects that are perpendicular to the magnetic field produce the most pronounced indications. The magnetic particles become attracted to discontinuities due to the high flux concentrations at the affected areas.

For low-carbon steels (with little or no retentiveness), a continuous application of magnetic particles is done while the magnetizing current is on. The magnetizing current is usually DC, from rectified AC. It is more penetrating than AC, up to half an inch below the surface.

For high carbon steels, (with high retentiveness), magnetizing current is applied, and then the magnetic particles, after the current is switched off. The magnetizing current is generally AC stepped down from single phase AC voltage. It is effective to approximately one one-thousandth of an inch below the surface.

Magnetic particle inspection or “mag-particle,” as it is commonly referred to, is common for use in rotor component inspection of forgings, couplings, and steel wedges. It is excellent for detecting surface or near-surface defects such as cracks in ferromagnetic materials. It is simple to perform and cost effective.

It is somewhat limited in that it is applicable to ferromagnetic materials only, and does require some skill in interpretation of defect indications and recognition of irregular patterns.

LIQUID PENETRANT

Liquid-penetrating inspection is widely used for generators, specifically on most rotor components, since it can be applied to both ferrous and nonferrous materials. It is primarily used for retaining-ring inspection. It is considered to have greater sensitivity than magnetic particle inspection, and is also a very cost-effective method of NDE.

The equipment required generally consists of the following:

o Dye penetrating fluid, fluorescent or otherwise;
o Developer;
o Developer application equipment;
o Ultraviolet light source, if the fluorescent method is used.

Dye-penetrating examination is able to detect surface cracks and pitting or any discontinuity open to the surface and not readily visible to the eye.

The technique requires a clean surface and so preparation of the surface by cleaning and polishing is first required. Then the liquid penetrant is applied and allowed time to weep into discontinuities by capillary action. Once penetration is complete, the excess penetrant is removed by wiping but not completely cleaned away. Next developer is applied, which absorbs the penetrant and acts as a type of blotter. Defects are then easily seen by eye.

The limitations of LPI are that it only detects surface defects and it is also temperature sensitive. It should only be used in the range of 60 to 90°F. This is due to viscosity issues with the penetrant as temperature varies outside the above-mentioned range.

Figures 11.31 to 11.33 show some of the uses on generators for defect detection.

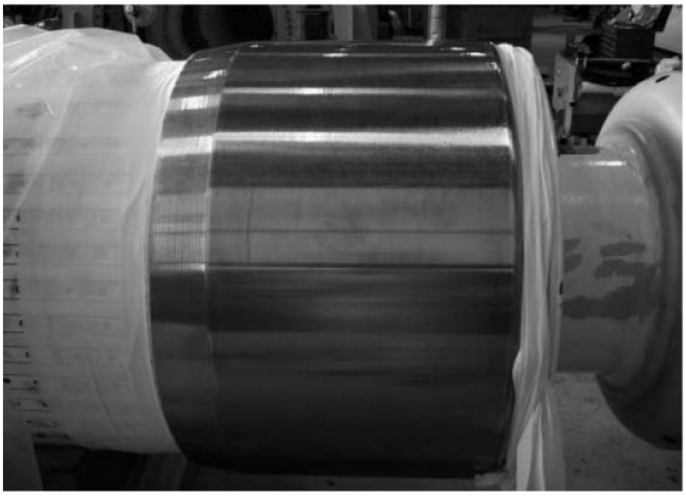


Fig. 11.31 18Mn-4Cr retaining ring-Fluorescent dye partially applied.

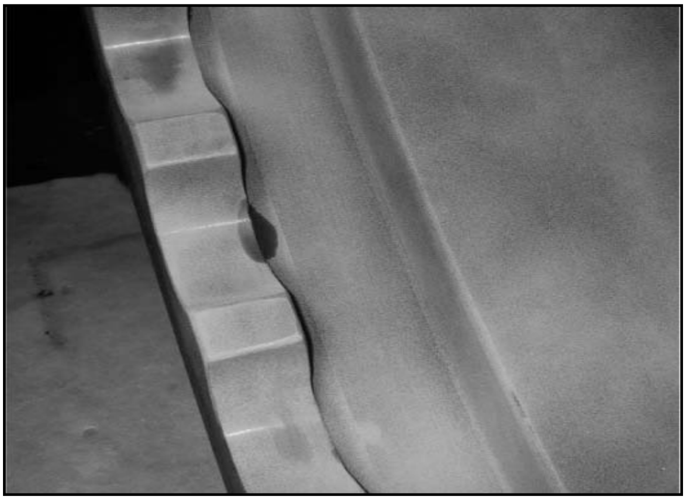


Fig. 11.32 18Mn-4Cr retaining ring-Developer applied and indication shown in the darkened spot at the castellated fitting.

Ultrasonic examination is probably the second most widely used NDE method on generator components. It is highly specialized and requires special commercial ultrasonic equipment, either of the pulse-echo or transmission type (Fig. 11.34).

UT is able to detect surface and subsurface flaws, including those too small to be detected by other methods. The size range in subsurface flaws is generally about 2 to 3 mm. Ultrasonic NDE is used for rotor forging bores, retaining rings, and specialized subsurface defects that can occur in high-stress areas or the rotor.

It is a very sensitive technique and can look at areas that are difficult access by other NDE methods. It does have the disadvantage that it is difficult to obtain good interpretable signals in areas where the specimen geometry is complex, such as the portion of a retaining ring where castellated fitting of the shrink fit area is employed. It also requires an operator with a high degree of training and skill to carry out the testing and interpret the results.

The two basic methods are described below:

PULSE-ECHO METHOD

The pulse-echo method is the most widely used method.

The ultrasonic pulse echo instrument generates high-voltage electrical pulses of short, evenly timed, duration. These pulses are applied to the transducer, which converts them into mechanical vibrations that are applied to the material being inspected. The sound reflected back to the transducer is converted back to electrical pulses, which are amplified and displayed on the cathode ray tube (CRT) as vertical pulses. The same transducer is used to transmit and to receive.

Through-Transmission Method

In the through transmission method, two transducers are required, one for sending and the other for receiving. Either short pulses or continuous waves are transmitted into the material. The quality of the material being tested is measured in terms of energy lost by a sound beam as it travels through the material.

To determine the location of discontinuities within a test

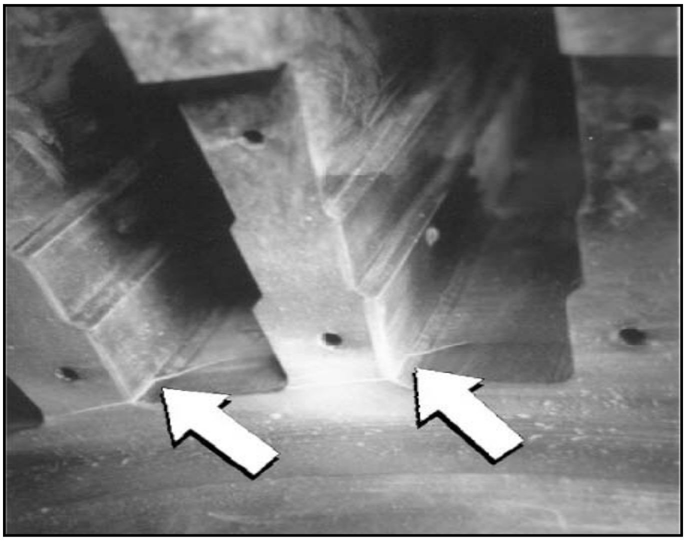


Fig. 11.33 Rotor forging tooth root cracks seen by fluorescent dye with developer applied.

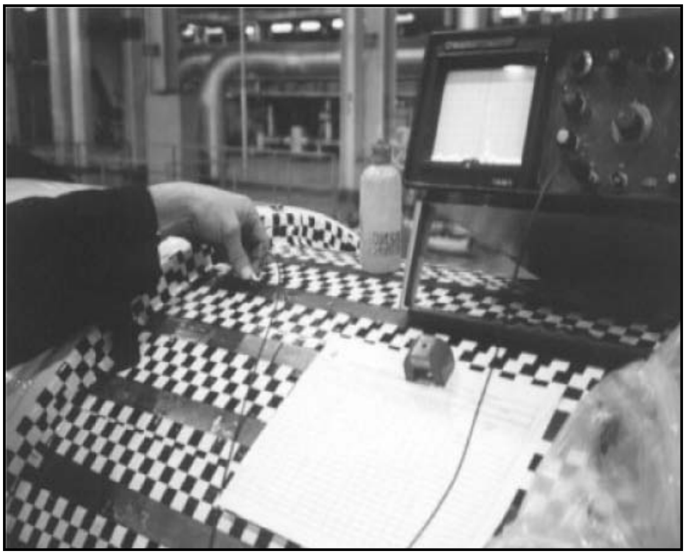


Fig. 11.34 Rotor forging tooth root cracks NDE by ultrasonic measurement with a 45-degree angle probe.

specimen, the visual display unit (VDU) horizontal display is divided into convenient increments such as centimeters or inches. At a given sensitivity (gain) setting, the amplitude is determined by the strength of the signal generated by the reflected sound wave.

The VDU thus displays two types of information: the distance (time) of the discontinuity from the transducer and the relative magnitude of the reflected energy.

There are generally two types of wave applications to the test specimen: longitudinal (compression) and shear (transverse) waves. Longitudinal waves have back and forth particle vibrations in the direction of the wave propagation. Shear waves have particle vibrations perpendicular to the direction of wave motion.

Shear waves will not travel through liquids or gasses. In some materials the velocity of a shear wave is about half that of longitudinal waves. Therefore the wavelength is shorter (by about half), permitting smaller discontinuities to be located.

Grain structure has a great influence on the acoustical properties of a material.

A steel forging generally has a fine-grain structure, and has a low-damping effect on the sound beam. A casting, however, generally has a coarser grain structure, which is more difficult to get sound through.

When a discontinuity is not normal (at 90 degrees) to the incident wave, the reflected wave will be at an angle. The result is a reduction in the amplitude of the discontinuity indication displayed on the CRT.

Transducers come in many shapes, sizes and physical characteristics. Some common types include paintbrush, dual element, single element, angle beam, focused, mosaic, contact, and immersion. Single-element transducers may be transmitters only, receivers only, or both. Double-element transducers may be single transducers mounted either side by side or stacked. In a double-element transducer, one is a transmitter and the other is a receiver. Double-element transducers have better near-surface resolution because the receiver can receive discontinuity signals before the transmitter completes its transmission.

EDDY CURRENT

Eddy-current examination requires very special commercial type equipment, consisting of the following components:

o Vector voltmeter;
o Differential bridge;
o Sensor coils;
o Frequency generator;
o Phase sensitive detector;
o Impedance plane display instrument.

Eddy current is not widely used for generator applications, but it has been useful on occasion where tight cracks in retaining rings cannot be seen by LPI, MPI, or UT. It is able to penetrate layers of good material to detect hidden flaws in metals such as inclusions and tight cracks. Examples of the types of defects that can be seen by eddy current are surface and near-surface defects, de-lamination of multi-layered components, and inclusions.

The basic principle is that of an alternating current flowing through a coil, producing an alternating magnetic field in the specimen being tested. When the coil is then placed near a test specimen that is conductive, the magnetic field causes eddy currents to flow. This flow of eddy currents depends on the physical and electrical characteristics of the test specimen. The eddy currents will avoid cracks and seek higher conducting regions in the specimen. As the eddy currents flow in the test specimen, they generate their own magnetic field. This field interacts with the magnetic field produced by the coil and changes the coil's impedance. Specialized instruments then measure and display these changes in the impedance, allowing the test technician to interpret information about the test specimen, specifically the presence and size of flaws in it.

There are numerous types of eddy current probes used, and the type of probe chosen depends on the material being tested and the application. The types of probes are absolute, differential, reflection, unshielded, and shielded. The main advantages to this method in general are low cost, ease and speed of use, high sensitivity to microscopic defects, and its automation.

11.6.3 SOME ADDITIONAL ROTOR NDE SPECIFICS

NDE tests are generally done on the following generator rotor components:

o Forging;
o Retaining-rings;
o Fans.

Typical NDE tests include magnetic particle, liquid penetrant, ultrasonic (and bore-sonic), and sometimes eddy current. An additional test hardness test is sometimes performed.

ROTOR FORGINGS

NDE is most often done during rewinding of the rotor, when re-validation of the forging is required. This may include the following inspections:

o Magnetic particle inspection (MPI) of the rotor fillet radii inboard of the journals, shaft radius at the slot exit interface, fan seating and keyways, pole face crosscuts, pole and winding slots, and so on;

o Liquid penetrant inspection (LPI) of the exciter end lead slot radii, inboard and outboard radial pinholes, and coupling bolt holes;

o Ultrasonic examination of the rotor bore (boresonic).

In addition, the rotor forging generally undergoes full-dimensional checks and run-out or truth checks.

FANS

Rotor fans are highly stressed components of the rotor. Fan blades and vanes are generally tested by LPI and UT.

RETAINING-RINGS

Retaining-rings are by far the component subjected to the highest scrutiny during major overhauls. One of the most comprehensive studies on this topic is given in the EPRI Special Report EL/EM-5117-SR, “Guidelines for Evaluation of Generator Retaining-Rings,” April 1987 [18].

Generally, generator rotors employ three different types of retaining-ring material.

These are Ni-Cr-Mo-Va magnetic steel (ferritic), 18Mn-5Cr nonmagnetic steel, and 18Mn-18Cr nonmagnetic steel.

One of the major station concerns is the ability to perform NDE on large generator rotor retaining-rings without removing the rotors from the generator, let alone the retaining-rings from the rotors. This is driven by the high cost of rotor removal and subsequent removal of the retaining-rings from the rotors, and the time consumption involved. In addition, removing retaining-rings is not desirable because of the risk of damaging the rings, the rotor forging, and/or end-windings in the process.

Retaining-rings constructed from magnetic material are generally sound in terms of strength and resistance to corrosion, and so on. However, they are undesirable with regard to their electromagnetic characteristics and resulting effect on the overall machine losses.

Generator rotor retaining-rings made from 18Mn-5Cr austenitic, nonmagnetic steel are, on the other hand, highly susceptible to the mechanism of stress corrosion cracking when exposed to a moisture laden environment during operation or at a standstill. This has become an industrywide problem without regard to a specific manufacturer.

Several ring failures have occurred in the industry, resulting in considerable damage to the overall generators and their support structures. These incidents were attributed to stress corrosion cracking caused by exposure to moisture.

These rings had apparently not been adequately protected from the environment.

Once a crack has been initiated, the propagation rate of the crack will depend on, the ring design (geometry, stress levels, etc.), environment and the operating conditions to which it is subjected. It is extremely difficult to predict when small cracks will reach the critical crack size to which failure is imminent. An attempt has been made and is published. Inspection is the only means available to assess retaining-ring integrity, and provide an opportunity to correct problems encountered.

With the advent of a new retaining-ring material known as 18-18 (18Mn-18Cr), which is highly resistant to the stress corrosion cracking mechanism, all manufacturers are advocating that the 18Mn-5Cr retaining rings be replaced with new 18-18 rings because of their superior properties. 18Mn-18Cr steel is claimed to be very resistant to corrosion and stress corrosion cracking in the operating environments of large generators. As a result, fewer inspections will be needed for the retaining-rings.

Testing Frequency. Depending on availability, it is desirable to conduct retaining-ring inspections during a period of one to two years following the in-service date, and again six to eight years after that. Subsequent inspections are prescribed based on a combination of information gained during previous inspections, and adverse operating conditions since the last inspection.

Adverse operating conditions would include water leakage into the generator, high or sustained dewpoint excursions, local system faults, synchronizing errors, high rotor temperature excursions, continuously changing load requirements or two shifting, overspeeds, rotor at standstill in uncontrolled environmental conditions, and so on.

Inspection Procedure. The recommended process for an acceptable assessment of retaining-ring integrity requires removal of both rings from the rotor body completely. A thorough cleaning of all ring surfaces prior to inspection follows this. The cleaning is achieved by hand polishing of shrink-fit areas, and by using electrically nonconductive abrasives on all surfaces to achieve bare metal conditions.

The inspection is carried out during a detailed dye penetrant process, using a highly sensitive fluorescent liquid penetrant to expose suspect areas containing cracks, pits, or defects.

Local grinding and/or polishing will normally remove any flaws, but there are limitations on the amount of corrective action allowed. It is essential that the limits not be exceeded during the corrective action as the suspect areas are removed.

Removal of material from the shrink-fit area is limited to the amount at which 15% overspeed capability is maintained. The design overspeed capability is 20% above operating. Overspeed trips are set at 10%, thus allowing a minimum 5% margin for the material to be removed. The determination of the depth of the skim to be taken off the shrink-fit, when required, should be referred back to the OEM.

ACCEPTANCE CRITERIA

Acceptance criteria are normally determined by, and are the responsibility of, the manufacturer/supplier of the item being assessed.

However, acceptance criteria is usually based on detection of defects and not crack/pit/defect sizing. It is much easier to establish an acceptable situation by first establishing "not-acceptable" criteria.

A reasonable not-acceptable criteria adopted by some OEMs and users is as follows:

1. No linear defects > 1 mm in length.
2. No linear array of 3 or more point defects with < 3 mm between points.
3. No random groups of 3 or more point defects within a circle of < 5 mm diameter.
4. No random groups acceptable to criteria 3 but < 5 mm from a similar group.

Note: A point defect is a surface defect < 0.5 mm in diameter.

IN-SITU TESTING

At the present time, ultrasonic examination of retaining-rings assembled on a rotor body is being debated by users and testers in the industry.

There are some who are staunch proponents of the in-situ technique, while others insist it is not sensitive enough.

At last report to the authors, the smallest cracks that can be detected are in the order of 2 to 3 mm in the shrink area and only as small as 1 mm in the smooth bore areas. On rings with castellated fittings, it may not be possible to resolve indications identified due to the complex geometry involved.

It should also be understood that these crack sizes quoted above are large in terms of significance for retaining-rings. Even pitting marks will propagate into cracks when the internal generator hydrogen conditions are not good. The critical crack size is different for each ring design and must be evaluated independently.

The bottom line is that even the smallest cracks cannot be tolerated, especially in the shrink area. It is the modest opinion of the authors that the only way to know for sure if the ring is free of defects is to remove it for detailed NDE surface type inspection methods and ultrasonic or eddy current for detection of inclusions.

Finally, there are some in the industry who consider it desirable to install the new 18Mn-18Cr retaining-rings so that inspection is unnecessary. Figure 11.35 shows an in-situ testing device in operation.

11.6.4 AIR PRESSURE TEST OF ROTOR BORE

The vast majority of large generator rotors in existence have hollow bores, which extend the full length of the rotor forging. These boreholes are generally in the range of 3 to 5 inches (≈ 7.5-13 cm) in diameter, and when the contents of the bore are removed, one can see from one end right through to the other.

Boreholes were used mostly in past due to impurities and porosity in the forgings, which tended to concentrate in the center. They serve two purposes: the first is to remove the material defects, and the second is to provide an access for performing boresonic (ultrasonic) inspection of the rotor bore. In modern forgings the material manufacturing processes are so improved that a full rotor length borehole is not generally required. Only a short borehole at the exciter end of the rotor is provided to accommodate the up-shaft lead, which connects the rotor winding to the slip-rings via the radial terminal studs.

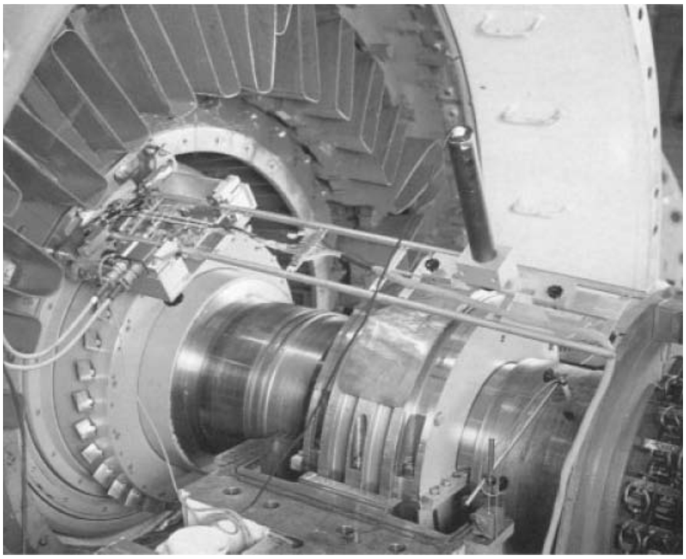


Fig. 11.35 In-situ robotic rotor retaining-ring ultrasonic testing. (Courtesy of Alstom).

In hydrogen cooled machines rotor seals are installed in the shaft, sealing the hole in the shaft where the up-shaft lead or bore copper is installed. This is between the sliprings and the field winding. The seals are generally made of rubbery material, which under pressure (sometimes from a nut) expands filling the area between the bolt connecting the bus/conductor in the hollow of the shaft to the slip-rings. On the excitation end, some rotors have only one set of seals close to the collectors, while other rotors have a second set of seals, where the leads exit shaft, under the retaining rings. On rotors with a full-length borehole the turbine end of the rotor is also sealed by a faceplate arrangement on the coupling face.

The integrity of the rotor seals is normally checked during major overhauls.

Depending on the design of the rotor, some can be pressure-tested by a nipple permanently installed on the shaft, or by placing a can over the shaft extension and collector assembly, tightly sealed against the rotor forging, and pressurizing the can.

11.7 ROTOR ELECTRICAL TESTING

11.7.1 WINDING RESISTANCE

The field-winding series-resistance is measured to determine the ohms resistance of the total copper winding in the rotor. Given the relatively low DC series resistance of windings of large machines, the measurement accuracy requires significance to a minimum of four decimal places.

The purpose of the test is to detect shorted turns, bad connections, wrong connections, and open circuits. The machine should be at room temperature when the test is performed. As with most other electrical test, the results should be compared with original factory data, if available.

11.7.2 INSULATION RESISTANCE (IR)

The purpose of the IR test is to measure the ohmic resistance between the total rotor winding insulation and ground (i.e., the rotor forging). This test is generally regarded as an initial test to look for gross problems with the insulation system and to ensure further high voltage electrical testing may (relatively) safely continue, in terms of danger of failing the insulation.

Normally, the measurements of IR will be in the megaohm range for good insulation, after the winding is subjected to a DC test voltage usually done anywhere from 500 to 1,000 V, for one minute. The minimum acceptable reading by IEEE Standard 43 is (Vf in kV + 1) M©. The test is carried out with a megger device. The DC test voltage level is usually specified based on the operating and field forcing voltage of the rotor, utility policy and previous experience, and knowledge of the present condition of the insulation in the rotor.

It is essential that the rotor winding be completely dried before any testing so that any poor readings will be due to a "real" problem and not residual moisture.

The readings are also sensitive to factors like humidity, surface contamination of the coils, and temperature. Readings should be corrected to a base temperature of 40°C (Fig. 11.24).

All of the above also applies to the rotor bore copper and collector rings.

11.7.3 POLARIZATION INDEX (PI)

Insulation resistance is time dependent as well as being a function of dryness for rotor insulation, just as in the stator. The amount of change in the IR measured during the first few minutes depends on the insulation condition, and the amount of contamination and moisture present. Therefore, when the insulation system is clean and dry, the IR value tends to increase as the dielectric material in the insulation absorbs the charge. When the insulation is dirty, wet, or a gross insulation problem is present, the charge does not hold. The IR value will not increase because of a constant leakage current at the problem area. Thus the ratio between the resistance reading at 10 minutes and the reading at 1 minute produces a number or "polarization index," which is essentially used to determine how clean and dry the winding is.

The recommended minimum PI values are as follows:

o Class B insulation: 2.0
o Class F insulation: 2.0

The same megger used for the IR readings should be used to determine the PI.

The PI readings should be done at the same voltage as the IR test and can be used as a go/no-go test before subjecting the rotor to subsequent high voltage tests, either AC or DC. The IR readings for the PI test should also be corrected to 40°C as in the IR test (Fig. 11.23). Performing the high-voltage tests on wet insulation can cause needless failure of the insulation.

11.7.4 DC HI-POT

The DC hi-pot test is used to ascertain if the winding is capable of sustaining the required rated voltage levels (without a breakdown of the insulation), with a reasonable degree of assurance for capability to withstand overvoltages and transients, and maintain an acceptable insulation life. The test consists of applying high voltage to the rotor winding for one minute.

The DC Hi-Pot testing on rotor windings is normally done between 1500 V up to approximately 10 times the rated field voltage.

11.7.5 AC Hi-Pot

The AC hi-pot test is also used to ascertain if the winding is capable of sustaining the required rated voltage levels (without a breakdown of the insulation) with a reasonable degree of assurance for capability to withstand overvoltages and transients, and maintain an acceptable insulation life. The test consists of applying AC high voltage to the rotor winding for one minute.

The AC hi-pot testing on rotor windings is also normally done at to 10 times the rated field voltage at line frequency of 60 Hz.

11.7.6 SHORTED TURNS DETECTION - GENERAL

Shorted turns in rotor windings are associated with turn-to-turn shorts on the copper winding, as opposed to turn to ground faults. Rotor winding shorted turns, or inter-turn shorts can occur from an electrical break down of the inter-turn insulation, mechanical damage to the inter-turn insulation allowing adjacent turn to turn contact, or contamination in the slot that allows leakage currents between turns.

When shorted turns occur, the total ampere-turns produced by the rotor are reduced, since the effective number of turns has been reduced by the number of turns shorted. The result is an increase in required field current input to the rotor to maintain the same load point, and an increase in rotor winding temperature.

At the location of the short, there is a high probability of localized heating of the copper winding and arcing damage to the insulation between the turns.

This type of damage can propagate and worsen the fault, such that more turns are affected or the ground-wall insulation becomes damaged, and a rotor winding ground occurs.

One of the most noticeable effects of shorted turns is increased rotor vibration due to thermal effects. When a short on one pole of the rotor occurs, a condition of unequal heating in the rotor winding will exist between poles. The unequal heating may cause bowing of the rotor, and hence vibration. The extent and location of the shorted turns and the heating produced will govern the magnitude of the vibrations produced.

A general relationship between the location of the shorted turn/turns and vibration is as follows:

o Lower vibration is generally experienced when the short is on the Q axis.

o Higher vibration is generally experienced when the short is nearer the pole or D axis.

Stated differently, the rotor is more prone to vibration due to shorted turns if the shorts are located in the “small coils” rather than in the “large coils”. The “small coils” being those located closer to the pole faces.

The reasoning for the above is the lack of symmetry with faults nearer the pole face. There is an inherent unbalance in the geometry and heating effect on the rotor forging.

Off-line methods for detecting shorted turns include winding impedance measurements as the rotor speed is varied from zero to rated speed, and RSO (recurrent surge oscillation) tests, based on the principle of time domain reflectometry.

In addition, a short of significant magnitude may be identified by producing an open circuit (OC) saturation curve, and comparing it to the design OC saturation curve. If the field current required to produce rated terminal voltage has increased from the original design curve, then a short is likely present. The number of shorted turns may be identified by the ratio of the new field current value over the design field current value.

All of these methods of identifying shorted turns are prone to error and only indicate that a short exists. They do little to help locate which slot the short is in and require special conditions for collecting the data or for testing. To better identify shorted turns, and to employ a method that works on line, the search coil method has been perfected. Each OEM has their own version of a search coil method, but all work essentially in the same manner.

11.7.7 Shorted Turns Detection by Recurrent Surge Oscillation (RSO)

In the RSO method, a low-voltage (a few volts) high-frequency (kHz range) surge wave is injected at each one of the collector rings. The two signals are then compared to determine if the same waveform is observed at each collector ring. If the waveform is identical, then no shorts are present. Variations in the two waveforms indicate shorts to be present. This method is based on the principle of time domain reflectometry.

This method has the advantage of allowing the rotor to be spun, while doing the measurements, to determine if the shorts are also speed sensitive. The advantage of this is that the mechanical loading effects can be taken into consideration. In the spinning RSO, there may be shorts that reveal themselves that are not seen when the rotor is at rest, since at rest there is no mechanical load on the winding turns other than their own weight.

Because the RSO also works on a time-of-flight principle, the location of the coil number where the shorts are, as well as which pole, becomes discernable by this method. Shorts nearer the slip-rings show up as blips in the RSO pulse nearer the left side of the traces. The magnitude of the blip increases for the number of turns shorted at the particular location (i.e., the particular coil) as more turns are shorted.

In the “at-rest” test, the RSO is connected directly to the winding via the collector rings. Thus only the winding impedance is seen by the high-frequency, low-voltage pulses sent by the RSO. In the “spinning” RSO test, to accommodate the moving rotor, the leads of the RSO must be connected to the brush-rigging, and the connection to the winding is then implemented via the brushes' collector rings. However, with this connection anything connected toward the excitation equipment is “seen” by the pulses (e.g., leads, contacts, field breaker, field resistor, and excitation equipment). The principle of operation of the RSO is comparing the pulses inserted in each polarity terminal of the winding, and their reflections. The test is extremely sensitive to any asymmetry on the path of the pulses. From a point of view of the wave impedance seen by the high-frequency pulses, the field winding is by nature very symmetrical, but the excitation system is anything but that. Therefore, in order to obtain any significant signature on the condition of the field-winding, the “noise” originating in the path toward the excitation must be reduced as much as possible. This is achieved by opening the excitation leads at a convenient location between the excitation system and the brush-rigging. After the leads are open, only cables of almost exactly equal length are left connected to the brush rigging. The effect introduced by these cables is generally negligible.

Figures 11.36 to 11.42 depict samples of RSO test-readings taken on a twopole turbogenerator rotor.

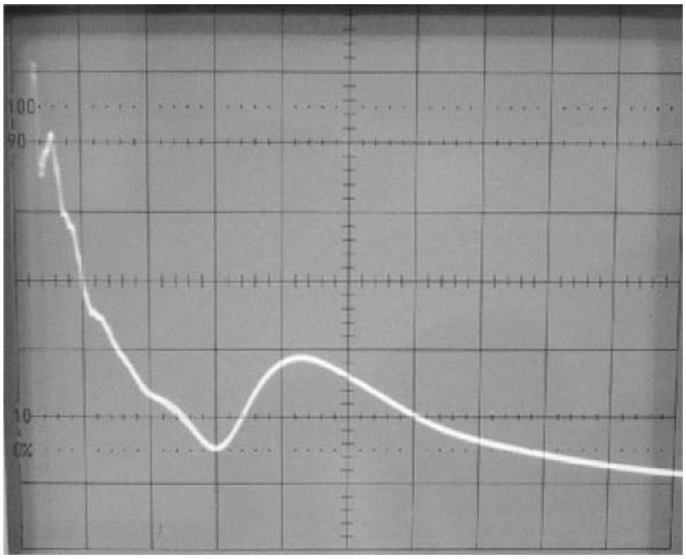


Fig. 11.36 No shorted turns - Dual traces superimposed.

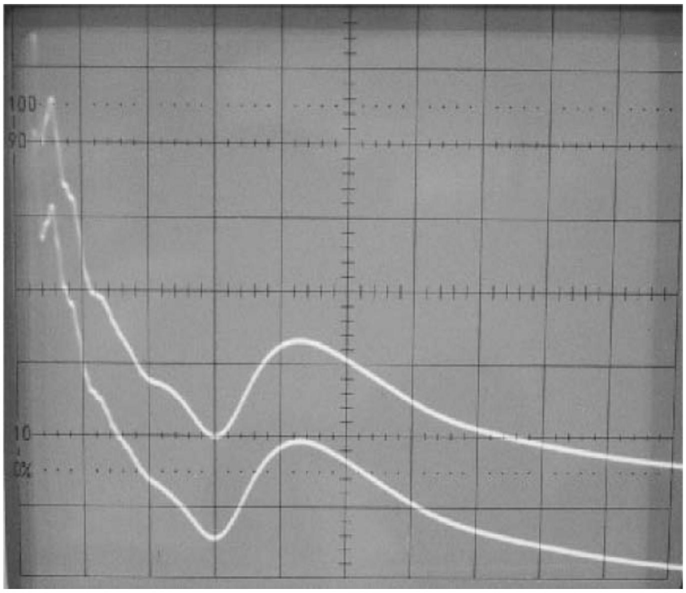


Fig. 11.37 No shorted turns - Dual traces separated.

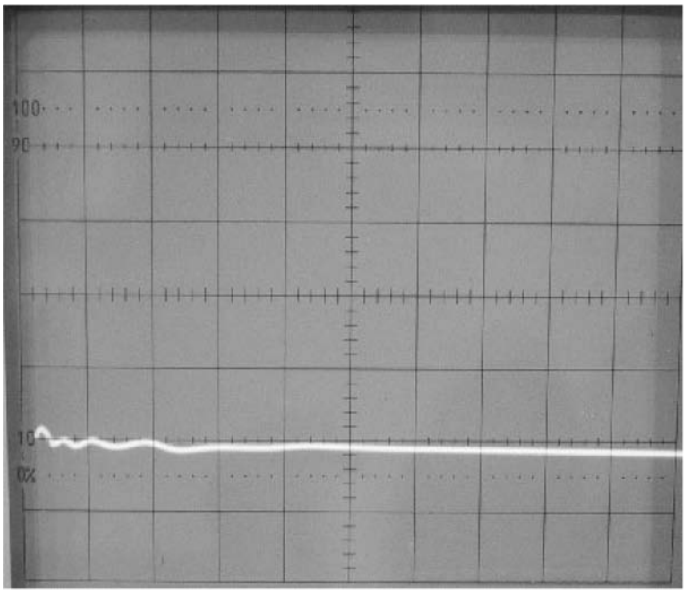


Fig. 11.38 No shorted turns - Difference trace.

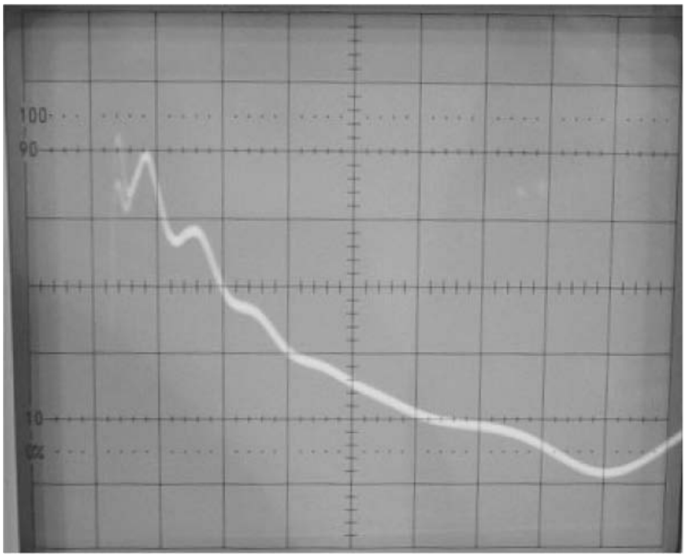


Fig. 11.39 One shorted turn, coil #1 - Dual traces superimposed.

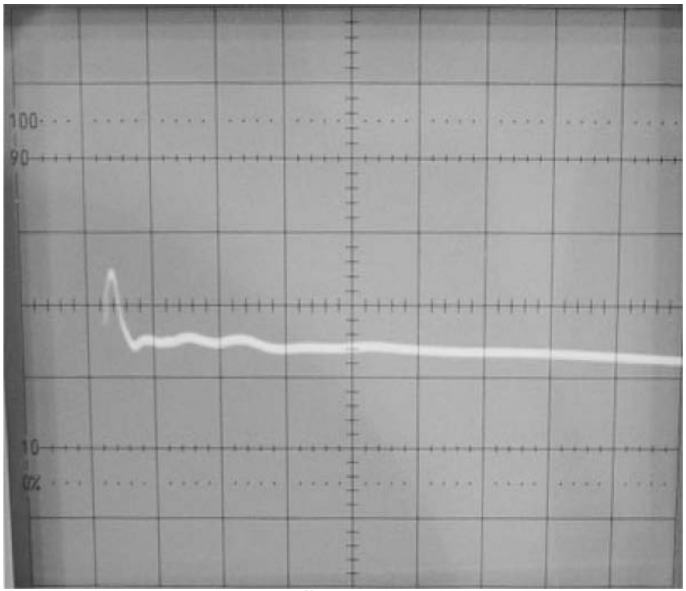


Fig. 11.40 One shorted turn, coil #1 - Difference trace.

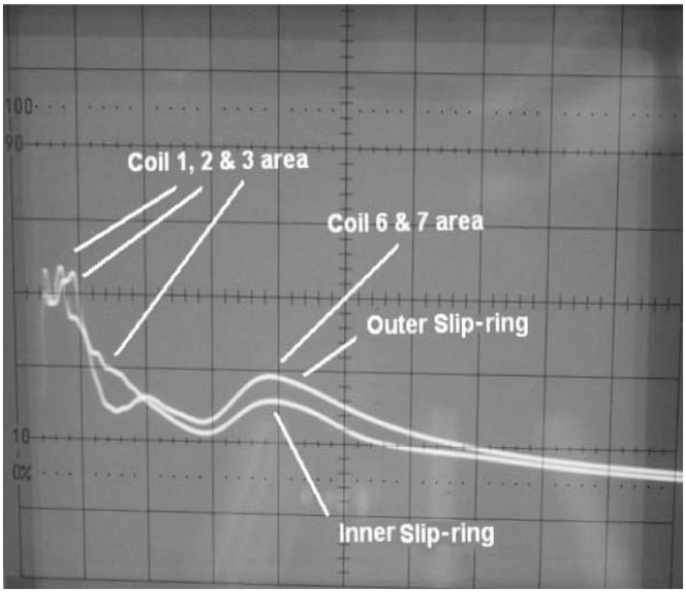
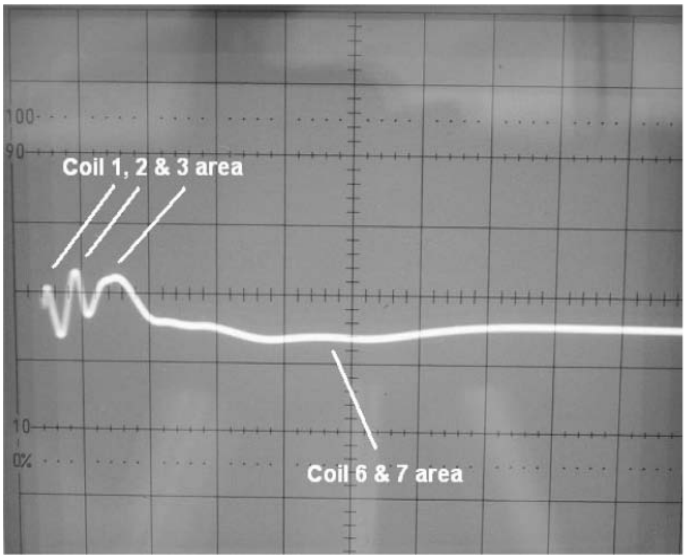


Fig. 11.41 Multiple shorted turns - Dual traces superimposed.



11.7.8 SHORTED TURNS DETECTION BY OPEN-CIRCUIT TEST

Producing an open-circuit saturation curve, and comparing it to the design open-circuit saturation curve may identify a shorted turn condition of significant magnitude.

If the field current required to produce rated terminal voltage has increased from the original design curve, then a short would be likely present (Fig. 11.43).

The number of shorted turns may be identified by the ratio of the new field current value over the design field current value. However, due to the many number of turns in a typical rotor winding, the changes in open-circuit voltage due to a single shorted turn in the field-winding may go unnoticed since the measurement is too small for a positive identification.

The open-circuit stator voltage versus field current characteristics can be measured in all synchronous machines. This curve, taken with the machine spinning at synchronous speed, is unique for each machine. In principle, the OC test allows detecting shorted turns in brushless machines, where RSO techniques are too difficult to perform, and always entails partial disconnection of the rotor leads.

11.7.9 SHORTED TURNS DETECTION BY WINDING IMPEDANCE

Impedance measurements while the machine is decelerating or accelerating can also be used to detect a speed-dependent shorted turn. Any sudden change in the readings may indicate a shorted turn being activated at that speed. A gradual change of impedance of more than 10% may also indicate a solid short (Fig. 11.44).

11.7.10 SHORTED TURNS DETECTION BY LOW-VOLTAGE DC OR VOLT DROP

This test is designed to determine the existence of shorted turns in the rotor winding. The test is entirely different when performed on salient pole rotors than in cylindrical (round) rotors.

In salient pole machines, a "pole drop" test is done. In this test, the resistance across each individual pole is measured by the V/I method, namely by applying a voltage of around 100 to 120 volts, 60 Hz, to the entire winding, and then measuring the voltage drop across each pole. A pole with lower voltage

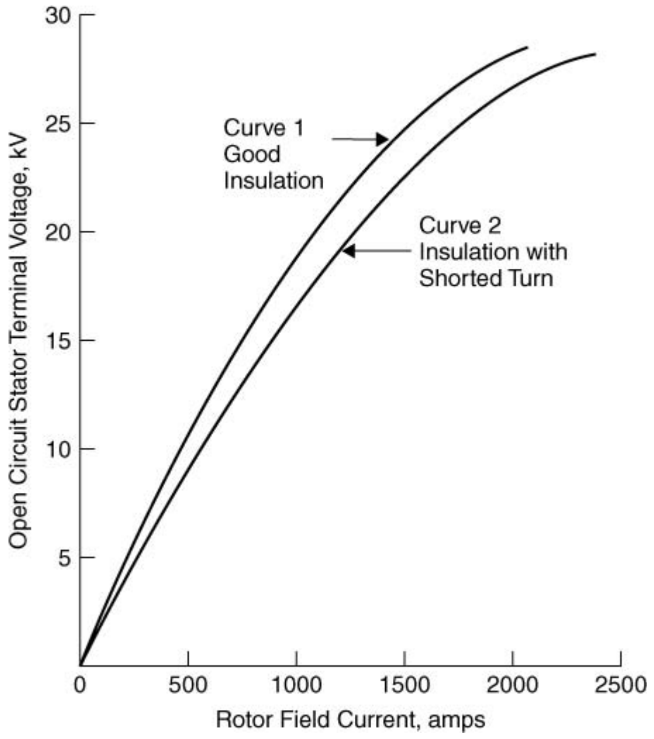


Fig. 11.43 Shorted turns detection by open-circuit saturation curve. (Courtesy of EPRI).

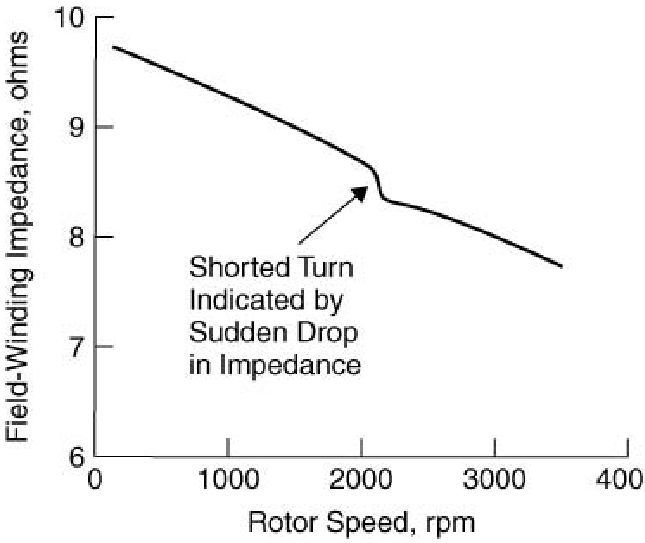


Fig. 11.44 Shorted turns detection by impedance testing. (Courtesy of EPRI).

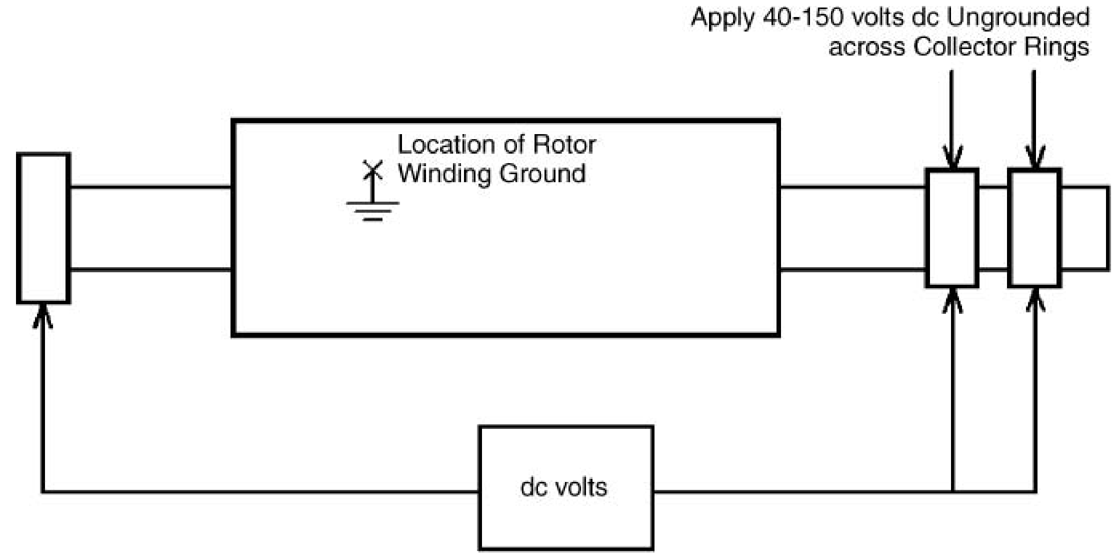

Apply 40-150 volts dc Ungrounded across Collector Rings
Location of Rotor Winding Ground
dc volts

Fig. 11.47 Rotor ground detection by split voltage test.

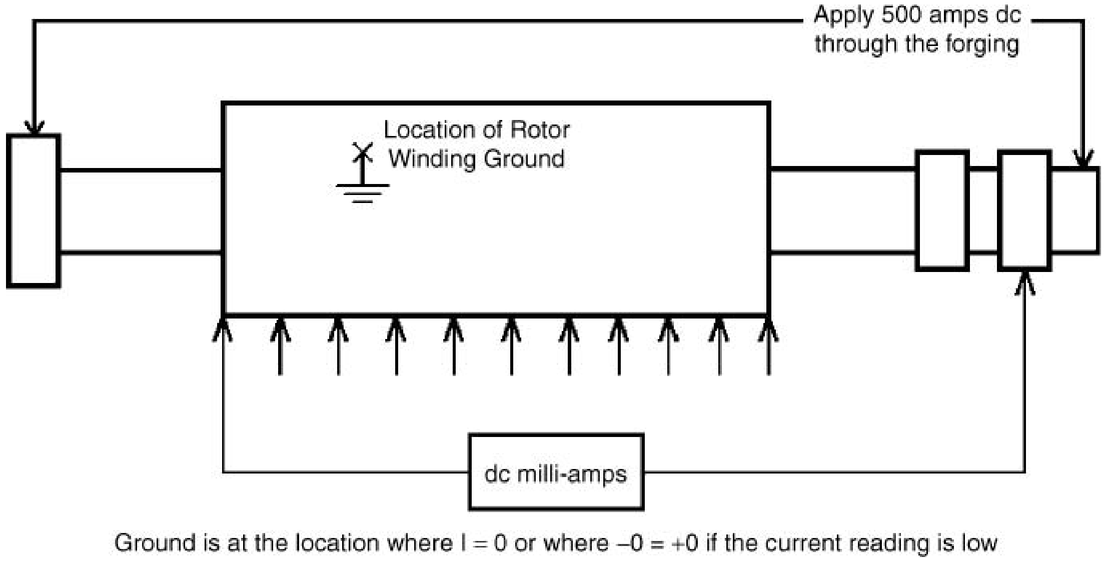

Apply 500 amps dc through the forging
Location of Rotor Winding Ground
dc milli-amps
Ground is at the location where I = 0 or where –0 = +0 if the current reading is low

Fig. 11.48 Rotor ground detection by current through forging test.

drop will indicate a shorted turn or a number of shorted turns.

In either salient pole or round rotor machines, the shorted turns are often speed dependent (i.e., they might disappear at standstill). To partially offset this phenomenon, it is recommended to repeat the pole drop test a few times with the rotor at several angles. The gravity forces exerted on the vertically located poles may activate some short circuits between turns, which might not show up when in, or close to, the horizontal position.

In round rotors, the individual windings are generally not accessible unless the retaining rings are removed. Therefore, detection of shorted turns in not always possible by this method.

11.7.11 SHORTED TURNS DETECTION BY LOW-VOLTAGE AC OR "C" CORE TEST

A C-shaped, wound core is required to carry out this test, together with a voltmeter, wattmeter, and single-phase power supply (Fig. 11.45). Shorted turns are detected by sharp changes in the direction of wattmeter readings (Fig. 11.46).

In rotors with damper windings, or with the wedges short-circuited at the ends to form a damper winding, these have to be disconnected at the ends. This operation requires removal of the retaining rings.

11.7.12 SHORTED TURNS DETECTION BY SHORTED TURNS DETECTOR (FLUX PROBE)

The flux probe is actually a search coil mounted on the stator core by various methods, but located strategically in the airgap. The search coil looks at the variation in magnetic field produced in the airgap by the rotor as it spins. The energized rotor winding and the slotted effect of the winding arc cause a sinusoidal signal to be produced in the winding face of the rotor. The pole face, on the other hand, has no winding and the signal is more flat since the variation in magnetic field is minimal.

The magnitude of the sinusoidal peaks in the winding face is dependent on the ampere-turns produced by the winding in the various slots. If there is a short in a slot, then the peak of the signal for that affected slot will be reduced. The reduction will be dependent on the magnitude of the short. Therefore, besides learning which slot the short is in, an estimate of the number of shorted turns can be made fairly accurately.

Problems due to saturation effects at full load can occur in analyzing the data and most OEMs now have a dedicated monitor connected to the flux probe to automate the analysis process. This allows the flux probe and monitor to act as standalone sensor to alarm when a short turn is detected and notify the operator for investigation.

Probably the most effective method for the detection of shorted turns in solid rotors is the flux probe method. This device maps the flux of the machine as it rotates, indicating possible shorts as changes in the measured waveform. Its main advantage is that it works with the rotor online, capturing the speed-dependent shorts. Its main disadvantages are the expertise required in analyzing the recorded waveforms, and the fact that the machine has to be de-energized and de-gassed for the installation of both core-mounted and wedge-mounted types of probes.

New commercially available units intended for on-line continuous operation, include software that analyzes the waveform and alerts to a possible shorted turn condition.

11.7.13 FIELD-WINDING GROUND DETECTION BY SPLIT VOLTAGE TEST

The “split voltage” test is used locate rotor grounds as a percentage through the field-winding.

For this test to be effective, the resistance to ground of the fault must be less than 5% of the balance of the rotor insulation, and the voltmeter must have high input impedance, when compared to the ground fault. The retaining rings should also be left on in case the ground is to one of the rings.

The test is done by applying up to 150 volts DC, ungrounded, across the slip-rings. A measurement of DC voltage is then taken from the rotor coupling at the turbine end of the forging to one of the collector rings. A measurement is next made from the other collector ring and the same location on the rotor coupling at the turbine end. This way, the two voltage measurements can be compared to estimate how far into the winding the ground has occurred. If the two measurements are equal, the rotor ground fault should be found in the middle of the winding. If there is less than 2% difference between the two readings, then the ground could possibly be at the collector rings.

This test is very useful in helping to determine how much dismantling is required to find the ground. Depending on where the ground is located, it can obviously make a big difference in the time expended to find the fault (Fig. 11.47).

11.7.14 FIELD GROUND DETECTION BY CURRENT THROUGH FORGING TEST

The current through forging test is another test used to locate rotor-winding grounds. In this particular application, the test is used to locate the actual “axial” position of the ground. The retaining-rings should be left on the rotor in case the ground is at one of the rings.

For this test, a DC current of about 500 amps is put through the forging from the tip of the forging at the slip-ring end to the coupling at the other end. A DC ammeter is used to look for the ground position. This is done by attaching one lead of the ammeter to the most outboard slip-ring, and then using the other lead to probe along the axial length of the rotor forging. At the point where the ground is, the current should reduce to zero, or if the current is not zero but only very low, then there will be a polarity change at the ground location (Fig. 11.48).

11.7.15 SHAFT VOLTAGE AND GROUNDING

During operation, voltage may rise on the generator rotor shaft, unless the shaft is grounded. The sources of shaft voltage are well established and identified as voltage from the excitation system due to unbalanced capacitive coupling, electrostatic voltage from the turbine due to charged water droplets impacting the blades, asymmetric voltage from unsymmetrical stator core stacking, and homopolar voltage from shaft magnetization. If these voltages are not drained to ground, they will rise and break down the various oil films at the bearings, hydrogen seals, turning gear, thrust bearing, and so on. The result will be current discharges and electrical pitting of the critical running surfaces of these components. Mechanical failure may then follow.

Inadequate grounding of the rotor will also allow voltage to build on the generator rotor shaft. Inadequate grounding may be due to a problem with the shaft grounding brushes from wear (requiring replacement brushes) or a problem with the associated shaft grounding circuitry if a monitoring circuit is provided.

High shaft voltages can also be caused by severe local core faults of large magnitude, which impress voltages back on the shaft from long shorts across the core. Protection against shaft voltage buildup and current discharges is provided in the form of a shaft-grounding device, generally located on the turbine end of the generator rotor shaft. The most common grounding devices consist of a carbon brush or copper braid, with one end riding on the rotor shaft and the other connected to ground.

Shaft voltage and current monitoring schemes are also provided in many cases to detect the actual shaft voltage level and current flow through the shaft grounding brushes. This has the advantage of providing warning when the shaft grounding system is no longer functioning properly and requires maintenance.

There are numerous monitoring schemes available, and each OEM generally has its own system provided with the TG set when purchased. For older machines with only grounding and no monitoring, a monitoring system can usually be retrofit to the existing ground brushes. The OEM should be consulted when upgrading the shaft monitoring.

11.8 HYDROGEN SEALS

11.8.1 NDE

The main tests done on the hydrogen seals are liquid penetrant inspection (LPI) for cracks and other surface damage, and ultrasonic (UT) for babbit bonding to the seal ring components.

11.8.2 INSULATION RESISTANCE

Megger checks of the seal insulation to ground are done to ensure the rotor shaft is not grounded through the hydrogen seals. This is usually done at only 500 V DC.

11.9 BEARINGS

11.9.1 NDE

The main tests done on the generator rotor bearings are liquid penetrant inspection (LPI) for cracks and other surface damage, and ultrasonic (UT) for Babbitt bonding to the bearing shell.

11.9.2 INSULATION RESISTANCE

Megger checks of the bearing insulation to ground are done to ensure the rotor shaft is not grounded through the bearings. This is usually done at only 500 V DC.

11.10 THERMAL SENSITIVITY TEST AND ANALYSIS

11.10.1 BACKGROUND

The thermal stability analysis is performed when vibrations of unknown origin afflict the generator. The purpose of the analysis is to narrow the search for the origin of the vibrations by ascertaining if the vibrations are from changes in the magnitude of the field current (If) in the field-winding or from other origin.

Generator rotor thermal sensitivity is a phenomenon that occurs in the rotor when its vibration changes as the field current is changed. This has occurred on generators' fields of all manufacturers at one time or another. The thermal sensitivity can be caused by uneven temperature distribution circumferentially around the rotor, or by winding forces that are not distributed uniformly around the rotor's circumference, or by asymmetrical radial gap forces. The primary driver of this second cause is the large difference in coefficients of thermal expansion between the copper coils and the steel alloy rotor forging and components. If the rotor winding is not balanced both electrically and mechanically around the rotor, the generator rotor will be unevenly loaded, which can cause the rotor to bow and cause vibrations to change.

From experience, it is known that rotor thermal sensitivity rarely affects operation when the unit operates in the region between the rated power factor lines, because the rotor is below its rated temperature in this region of operation.

Vibrations due to a thermally sensitive rotor are mostly at running speed frequency.

The vibrations origin can be further discriminated as being “reversible or repetitive” and “irreversible”. Reversible vibrations are those in which the vibration vector, when plotted on a polar graph, will not shift (Fig. 11.49). Irreversible vibrations show a shifting vector (Fig. 11.50). These last ones are the most onerous, as they cannot be balanced over the long run. Almost invariable they result in a winding removal and rewind. To capture the presence of these vibrations, the constant MW test is done in both directions, namely with the field current changed both ways. Figures 11.49 and 11.50 show what to expect in both cases. In the figures the test is started in point A and ends in point G.

Field-related vibrations might indicate the presence of one or more of the following:

- Shorted turns in the field-winding (vibration vector is reversible vs. If for a given number of shorted turns);
- A ratcheting effect (i.e., coils shift to one side of the rotor and the vibration vector becomes irreversible);
- “Sticky coil” (vibration vector tend to be reversible, but vibration changes might be “jumpy”);
- Crease under the retaining-ring (vibration vector may be reversible in the short run but might be of a ratcheting nature in the long run);
- Partial blockage of gas paths inside the rotor (vibration vector is reversible in the short and medium turn, and irreversible if insulation keeps moving- reversible during the test);
- Rotor stiffness dissymmetry (reversible vibrations);
- Wedges that were partially replaced during overhaul, and are not of identical dimensions, resulting in uneven fit along the circumference (vibrations tend to be

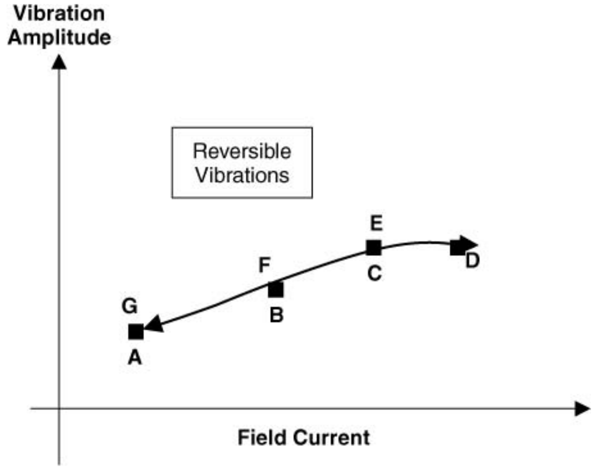


Fig. 11.49 Reversible vibrations in a thermal sensitive rotor. Note that the vibrations have a given value at a given load point. Changing loads will change the vibration, but it will always be the same for a given load. In the rotor of the graph the field current was changed from A to D back to G(= A). As the field current is decreased, the vibrations come back to their original value for each load point.

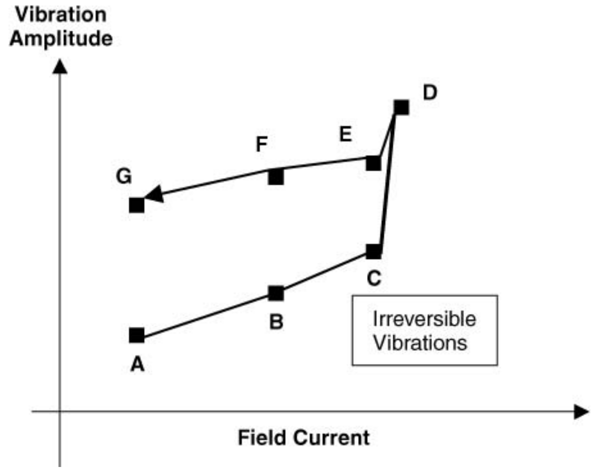


Fig. 11.50 Unlike the situation shown in the previous figure, in the present case the vibrations are not reversible. With every cycle of load they “creep up.” This situation has the potential of requiring a major repair of the rotor in short order.

reversible);
- Insulation that broke and shifted in the slots (reversible or irreversible during test, depending on severity of insulation damage);
- Nonhomogenous forging (vibration vector is reversible - vibration pattern will show up when unit is new or after repair of the forging, e.g., welding and machining).

If the unit does not indicate a field-current dependency, then most probably vibrations are of a mechanical nature.

ROTOR POSSIBLE CAUSES:

- Rotor mechanical unbalance due to a mass shift
  Retaining-ring movement
  Balancing weights shift
  Wedges shift
  Fan shift
  Shift of blocking under the retaining-rings
  Any other mass shift
- Crack in the rotor forging or on one of its components;
- Loose components.

STATOR/FRAME POSSIBLE CAUSES:

- Uneven heating of the stator coils, core, and frame;
- Bearing misalignment;
- H2 seals rub;
- Coupling misalignment;
- Loose footing;
- Loose components;
- Frame twisted.

11.10.2 TYPICAL THERMAL SENSITIVITY TEST

In order to segregate between the various sources, a thermal sensitivity test is performed. The following variables are recorded during the test (others may be added to the list). All manufacturers of large generators perform this type of test with some variances, under one name or another. The following description captures the most common approaches. Consult with the OEM of your unit for the test on your machine.

- MW;
- MVAR;
- Terminal volts;
- Terminal current;
- Field voltage;
- Field current;
- Vibration of all bearings of interest;
- Temperatures of interest;
- Time (hours, minutes) to stamp and correlate all readings.

It is important to verify the unit remains within its capability curve under the entire duration of the test. For that purpose, it is convenient to plan the load points ahead of the test, though it is not critical the actual load points selected during the test closely match those in the plan.

The test has three main parts:

CONSTANT MW AND MVAR

The aim of this test is to capture a rotor that is thermally sensitive due to forging asymmetries (due to the forging process or to machining, welding, etc.), or to stator-frame issues. During this part of the test, the unit's active and reactive power is held constant (AVR manual). The temperature of the generator's hydrogen is changed in steps by controlling flow of cooling water to the hydrogen heat exchangers. Stator water temperature is not changed. It is important to ascertain the unit remains within its temperature operating limits. Readings are taken when the temperatures are stable, and the time is noted (hours, minutes). This test is done at a reduced load point, to “make room” for temperature increases during the test.

CONSTANT MW

During this part of the test, the generator's gross MW output must remain constant. With MW constant, the field current (If) is changed (thus the VARs also change), and readings are taken of the variable parameters. The test is repeated for a number of field-current values. After a new If is set, the machine is let run for a given time to allow temperatures to stabilize, and then the readings are noted and the time is noted. The field current is changed in both directions, to capture “ratcheting” problems.

CONSTANT FIELD CURRENT (IF)

During this part of the test, the If must remain constant - the AVR must be set to manual. Under this condition the MW of the generator is changed in steps. After every change the unit is allowed to stabilize, and readings of the variables of interest are taken and the time is noted.

By analyzing the test results, it is possible to reduce the number of possible causes to one or a very small number. This is very important as it helps minimize the cost of any required outage and repair.

ISOLATION TECHNOLOGIES FOR RELIABLE INDUSTRIAL MEASUREMENTS

National Instruments Corporation

OVERVIEW

Voltage, current, temperature, pressure, strain, and flow measurements are an integral part of industrial and process control applications. Often, these applications involve environments with hazardous voltages, transient signals, common-mode voltages, and fluctuating ground potentials capable of damaging measurement systems and ruining measurement accuracy. To overcome these challenges, measurement systems designed for industrial applications make use of electrical isolation. This white paper focuses on isolation for analog measurements, provides answers to common isolation questions, and includes information on different isolation implementation technologies.

UNDERSTANDING ISOLATION

Isolation electrically separates the sensor signals which can be exposed to hazardous voltages (Hazardous Voltages are greater than 30 Vrms, 42.4 Vpk or 60 VDC), from the measurement system's low-voltage backplane. Isolation offers many benefits including:

- Protection for expensive equipment, the user, and data from transient voltages
- Improved noise immunity
- Ground loop removal
- Increased common-mode voltage rejection

Isolated measurement systems provide separate ground planes for the analog front end and the system backplane to separate the sensor measurements from the rest of the system. The ground connection of the isolated front end is a floating pin that can operate at a different potential than the earth ground. Figure 1 represents an analog voltage measurement device. Any common-mode voltage that exists between the sensor ground and the measurement system ground is rejected. This prevents ground loops from forming and removes any noise on the sensor lines.

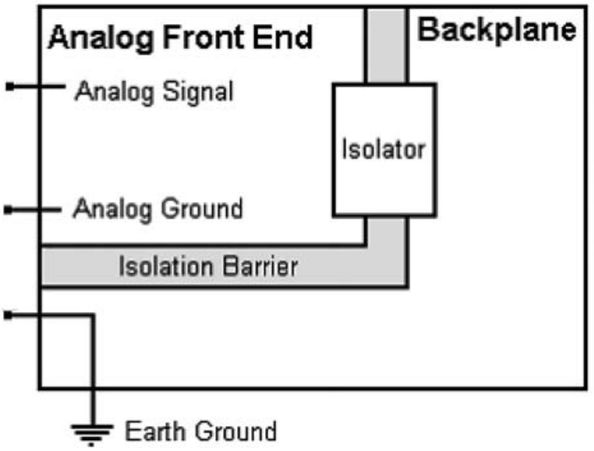


Figure 1. Bank Isolated Analog Input Circuitry

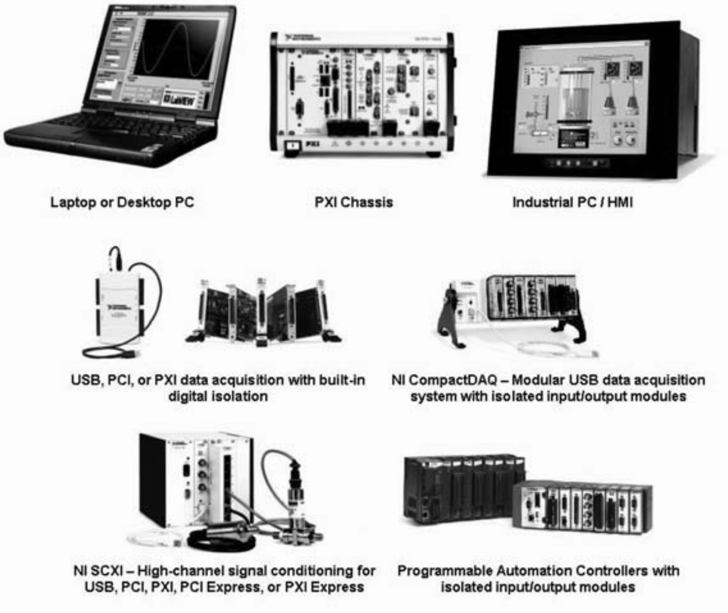
NEED FOR ISOLATION

Consider isolation for measurement systems that involve any of the following:

- Vicinity to hazardous voltages
- Industrial environments with possibility of transient voltages
- Environments with common mode voltage or fluctuating ground potentials
- Electrically noisy environments such as those with industrial motors
- Transient sensitive applications where it is imperative to prevent voltage spikes from being transmitted through the measurement system

Industrial measurement, process control, and automotive test are examples of applications where common-mode voltages, high voltage transients, and electrical noise are common. Measurement equipment with isolation can offer reliable measurements in these harsh environments. For medical equipment in direct contact with patients, isolation is useful in preventing power line transients from being transmitted through the equipment.

Based on your voltage and data rate requirements, you have several options for making isolated measurements. You can use plug-in boards for laptops, desktop PCs, industrial PCs, PXI, Panel PCs, and CompactPCI with the option of built-in isolation or external signal conditioning. Isolated measurements can also be made using programmable automation controllers (PACs) and measurement systems for USB.



Laptop or Desktop PC

PXI Chassis

Industrial PC / HMI

USB, PCI, or PXI data acquisition with built-in digital isolation

NI CompactDAQ – Modular USB data acquisition system with isolated input/output modules

NI SCXI – High-channel signal conditioning for USB, PCI, PXI, PCI Express, or PXI Express

Programmable Automation Controllers with isolated input/output modules

Figure 2. Isolated Data Acquisition Systems

METHODS OF IMPLEMENTING ISOLATION

Isolation requires signals to be transmitted across an isolation barrier without any direct electrical contact. Light emitting diodes (LEDs), capacitors, and inductors are three commonly available components that allow electrical signal transmission without any direct contact. The principles on which these devices are based form the core of the three most common technologies for isolation – optical, capacitive, and inductive coupling.

OPTICAL COUPLING

LEDs produce light when a voltage is applied across them. Optical isolation uses an LED along with a photo-detector device to transmit signals across an isolation barrier using light as the method of data translation. A photo-detector receives the light transmitted by the LED and converts it back to the original signal.

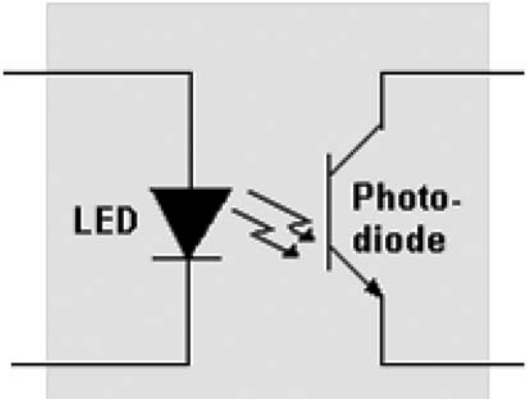


Figure 3. Optical Coupling

Optical isolation is one of the most commonly used methods for isolation. One benefit of using optical isolation is its immunity to electrical and magnetic noise. Some of the disadvantages include transmission speed, which is restricted by the LED switching speed, high-power dissipation, and LED wear.

CAPACITIVE COUPLING

Capacitive isolation is based on an electric field that changes based on the level of charge on a capacitor plate. This charge is detected across an isolation barrier and is proportional to the level of the measured signal.

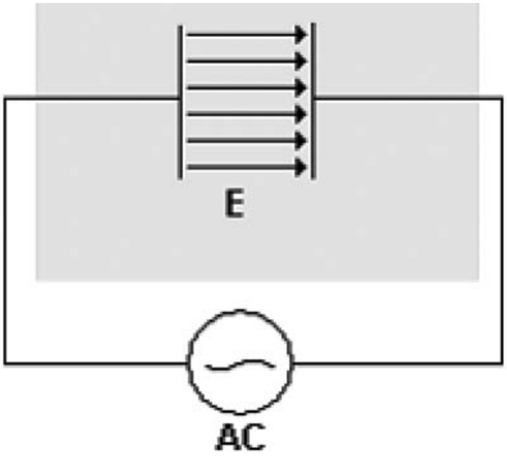


Figure 4. Capacitive Isolation

One advantage of capacitive isolation is its immunity to magnetic noise. Compared to optical isolation, capacitive isolation can support faster data transmission rates because there are no LEDs that need to be switched. Since capacitive coupling involves the use of electric fields for data transmission, it can be susceptible to interference from external electric fields.

INDUCTIVE COUPLING

In the early 1800s, Hans Oersted, a Danish physicist, discovered that current through a coil of wire produces a magnetic field. It was later discovered that current can be induced in a second coil by placing it in close vicinity of the changing magnetic field from the first coil. The voltage and current induced in the second coil depend on the rate of current change through the first. This principle is called mutual induction and forms the basis of inductive isolation.

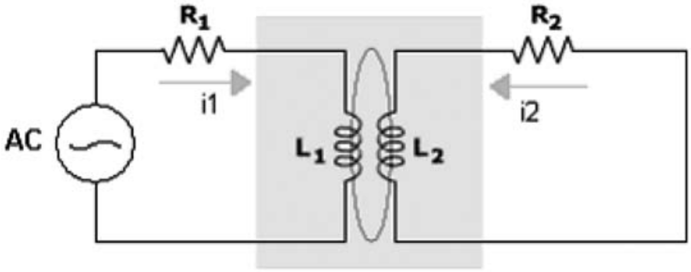


Figure 5. Inductive Coupling

Inductive isolation uses a pair of coils separated by a layer of insulation. Insulation prevents any physical signal transmission. Signals can be transmitted by varying current flowing through one of the coils, which causes a similar current to be induced in the second coil across the insulation barrier. Inductive isolation can provide high-speed transmission similar to capacitive techniques. Because inductive coupling involves the use of magnetic fields for data transmission, it can be susceptible to interference from external magnetic fields.

ANALOG ISOLATION AND DIGITAL ISOLATION

Several commercial off-the-shelf (COTS) components are available today, many of which incorporate one of the above technologies to provide isolation. For analog input/output channels, isolation can be implemented either in the analog section of the board, before the analog-to-digital converter (ADC) has digitized the signal (analog isolation) or after the ADC has digitized the signal (digital isolation). Different circuitry needs to be designed around one of these techniques based on the location in the circuit where isolation is being implementing. You can choose analog or digital isolation based on your data acquisition system performance, cost, and physical requirements. Figure 6 shows the different stages of implementing isolation.

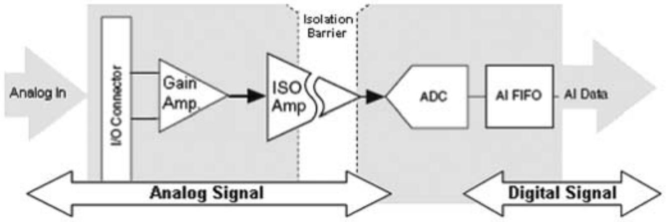


Figure 6a. Analog Isolation

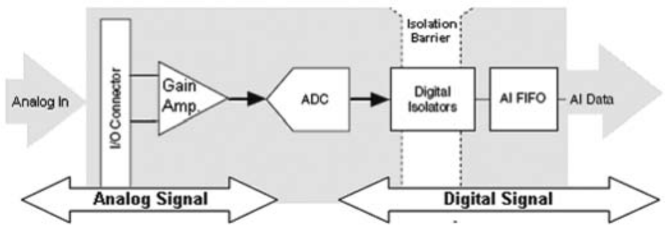


Figure 6b. Digital Isolation

The following sections cover analog and digital isolation in more detail and explore the different techniques for implementing each.

ANALOG ISOLATION

The isolation amplifier is generally used to provide isolation in the analog front end of data acquisition devices. "ISO Amp" in Figure 6a represents an isolation amplifier. The isolation amplifier in most circuits is one of the first components of the analog circuitry. The analog signal from a sensor is passed to the isolation amplifier, which provides isolation and passes the signal to the analog-to-digital conversion circuitry. Figure 7 represents the general layout of an isolation amplifier.

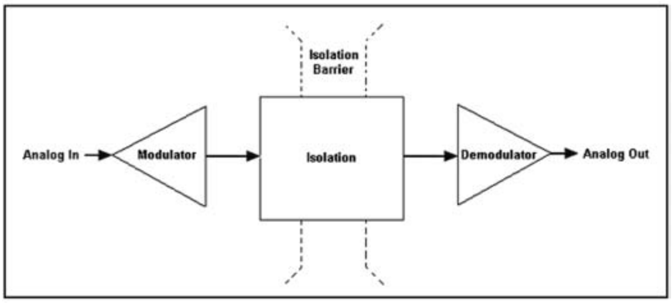


Figure 7. Isolation Amplifier

In an ideal isolation amplifier, the analog output signal is the same as the analog input signal. The section labeled "isolation" in Figure 7 uses one of the techniques discussed in the previous section (optical, capacitive, or inductive coupling) to pass the signal across the isolation barrier. The modulator circuit prepares the signal for the isolation circuitry. For optical methods, this signal needs to be digitized or translated into varying light intensities. For capacitive and inductive methods, the signal is translated into varying electric or magnetic fields. The demodulator circuit then reads the isolation circuit output and converts it back into the original analog signal.

Because analog isolation is performed before the signal is digitized, it is the best method to apply when designing external signal conditioning for use with existing non-isolated data acquisition devices. In this case, the data acquisition device performs the analog-to-digital conversion and the external circuitry provides isolation. With the data acquisition device and external signal conditioning combination, measurement system vendors can develop general-purpose data acquisition devices and sensor-specific signal conditioning. Figure 8 shows analog isolation being implemented with flexible signal conditioning that uses isolation amplifiers. Another benefit to isolation in the analog front end is protection for the ADC and other analog circuitry from voltage spikes.

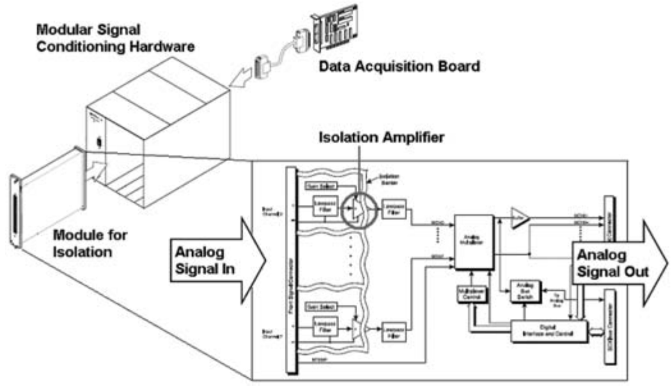


Figure 8. Use of Isolation Amplifiers in Flexible Signal Conditioning Hardware

There are several options available on the market for measurement products that use a general-purpose data acquisition device and external signal conditioning. For example, the National Instruments M Series includes several non-isolated, general-purpose multifunction data acquisition devices that provide high-performance analog I/O and digital I/O. For applications that need isolation, you can use the NI M Series devices with external signal conditioning, such as the National Instruments SCXI or SCC modules. These signal conditioning platforms deliver the isolation and specialized signal conditioning needed for direct connection to industrial sensors such as load cells, strain gages, pH sensors, and others.

DIGITAL ISOLATION

Analog-to-digital converters are one of the key components of any analog input data acquisition device. For best performance, the input signal to the analog-to-digital converter should be as close to the original analog signal as possible. Analog isolation can add errors such as gain, non-linearity and offset before the signal reaches the ADC.

Placing the ADC closer to the signal source can lead to better performance. Analog isolation components are also costly and can suffer from long settling times. Despite better performance of digital isolation, one of the reasons for using analog isolation in the past was to provide protection for the expensive analog-to-digital converters. As ADC prices have significantly declined, measurement equipment vendors are choosing to trade ADC protection for better performance and lower cost offered by digital isolators (see Figure 9).

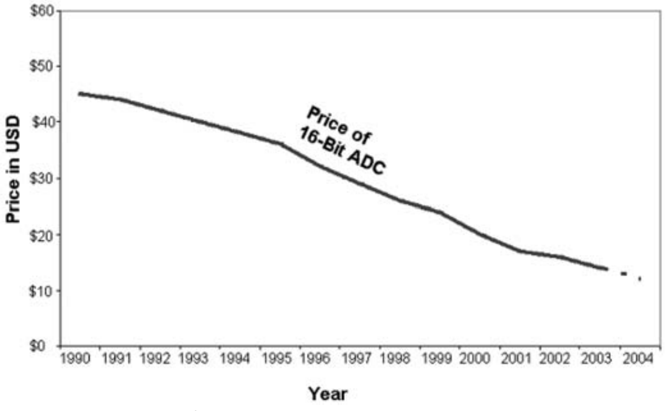


Figure 9. Declining Price of 16-Bit Analog-to-Digital Converters

Graph Source: National Instruments and a Leading ADC Supplier

Compared to isolation amplifiers, digital isolation components are lower in cost and offer higher data transfer speeds.

Digital isolation techniques also give analog designers more flexibility to choose components and develop optimal analog front ends for measurement devices. Products with digital isolation use current- and voltage-limiting circuits to provide ADC protection. Digital isolation components follow the same fundamental principles of optical, capacitive, and inductive coupling that form the basis of analog isolation.

Leading digital isolation component vendors such as Avago Technologies, Texas Instruments and Analog Devices have developed their isolation technologies around one of these basic principles. Avago Technologies offers digital isolators based on optical coupling, Texas instruments bases its isolators on capacitive coupling, and Analog Devices isolators use inductive coupling.

OPTOCOUPLERS

Optocouplers, digital isolators based on the optical coupling principles, are one of the oldest and most commonly used methods for digital isolation. They can withstand high voltages and offer high immunity to electrical and magnetic noise. Optocouplers are often used on industrial digital I/O products, such as the National Instruments PXI-6514 isolated digital input/output board (see Figure 10) and National Instruments PCI-7390 industrial motion controller.

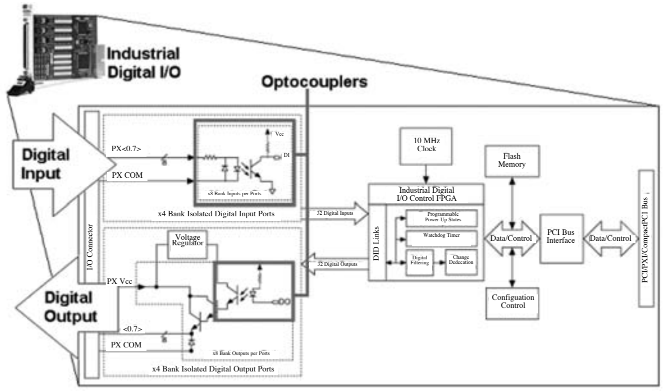


Figure 10. Industrial Digital I/O Products Use Optocouplers

For high-speed analog measurements, optocouplers, however, suffer from speed, power dissipation, and LED ware limitations associated with optical coupling. Digital isolators based on capacitive and inductive coupling can alleviate many optocoupler limitations.

CAPACITIVE ISOLATION

Texas Instruments offers digital isolation components based on capacitive coupling. These isolators provide high data transfer rates and high transient immunity. Compared to capacitive and optical isolation methods inductive isolation offers lower power consumption.

INDUCTIVE ISOLATION

iCoupler technology, introduced by Analog Devices in 2001, uses inductive coupling to offer digital isolation for high-speed and high-channel-count applications. iCouplers can provide 100 Mb/s data transfer rates with 2,500 V isolation withstand; for a 16-bit analog measurement system that implies sampling rates in the mega hertz range. Compared to optocouplers, iCouplers offer other benefits such as reduced power consumption, high operating temperature range up to 125°C, and high transient immunity up to 25 kV/ms.

iCoupler technology is based on small, chip-scale transformers. An iCoupler has three main parts – a transmitter, transformers, and a receiver. The transmitter circuit uses edge trigger encoding and converts rising and falling edges on the digital lines to 1 ns pulses. These pulses are transmitted across the isolation barrier using the transformer and decoded on the other side by the receiver circuitry (see Figure 11). The small size of the transformers, about three-tenths of a millimeter, makes them practically impervious to external magnetic noise. iCouplers can also lower measurement hardware cost by integrating up to four isolated channels per integrated circuit (IC) and, compared to optocouplers, they require fewer external components.

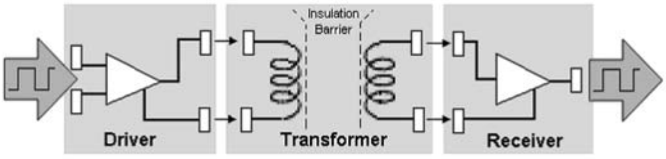


Figure 11. Induction Coupling-Based iCoupler Technology from Analog Devices

Source: Analog Devices

Measurement hardware vendors are using iCouplers to offer high-performance data acquisition systems at lower costs.

National Instruments industrial data acquisition devices intended for high-speed measurements, such as the isolated M Series multifunction data acquisition devices, use iCoupler digital isolators (see Figure 12). These devices provide 60 VDC continuous isolation and 1,400 Vrms/1,900 VDC channel-to-bus isolation withstand for 5 s on multiple analog and digital channels and support sampling rates up to 250 kS/s. National Instruments C Series modules used in the NI PAC platform, NI CompactRIO, NI CompactDAQ, and other high-speed NI USB devices also use the iCoupler technology.

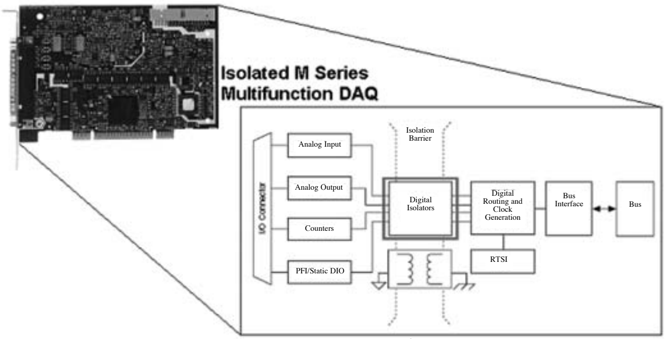
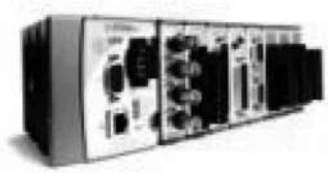


Figure 12. National Instruments Isolated M Series Multifunction DAQ Uses

SUMMARY

Isolated data acquisition systems can provide reliable measurements for harsh industrial environments with hazardous voltages and transients. Your need for isolation is based on your measurement application and surrounding environments. Applications that require connectivity to different specialty sensors using a single, general-purpose data acquisition device can benefit from external signal conditioning with analog isolation, whereas applications needing lower-cost, high-performance analog inputs benefit from measurement systems with digital isolation technologies.

Isolated Products from National Instruments

	NI Isolated M Series and S Series • NI USB-6218 - Bank isolated USB multifunction DAQ • NI PCI-6230 - Bank isolated PCI/PXI multifunction DAQ • NI PCI-6154 - Ch-Ch isolated PCI simultaneous sampling DAQ
	NI CompactDAQ - USB Data Acquisition System • NI 9211 - Bank isolated thermocouple input module • NI 9206 - Bank isolated 600 VDC CAT I analog input module
	NI SCXI High-Channel External Signal Conditioning • NI SCXI-1125 - Ch-Ch isolation amplifier • NI SCXI-1121 - Bank isolated universal input sensor measurement amplifier
	NI CompactRIO - Reconfigurable Embedded Control and Acquisition System • NI 9203 - Isolated current input module • NI 9422 - Ch-ch isolated digital input module
	NI Compact FieldPoint - Distributed Programmable Automation Controller • NI cFP-TC-125 - Ch-Ch isolated thermocouple input module • NI cFP-AI-118 - Ch-Ch isolated voltage input module
	NI Motion Plug-in Motion Controller with Isolation
	NI Serial RS-232 and RS-485 Devices with Isolation

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UNDERSTANDING INSULATION RESISTANCE TESTING

AEMC Instruments

WHY HAVE AN INSULATION TESTING PROGRAM?

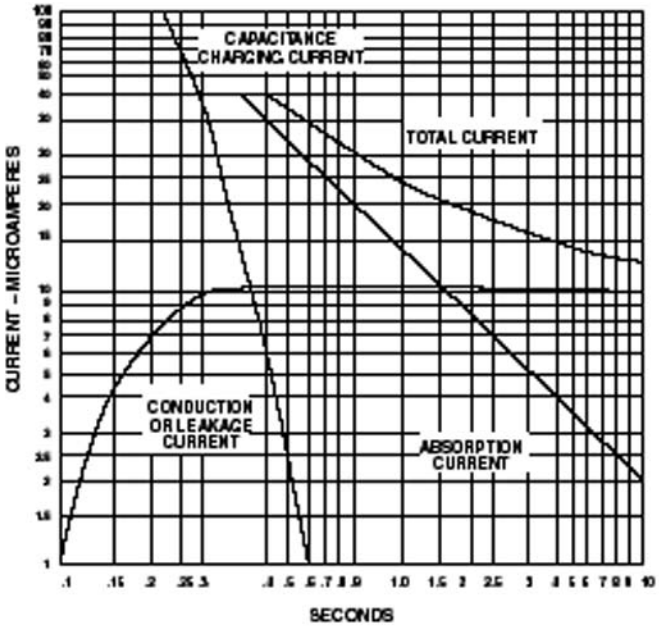
A regular program of testing insulation resistance is strongly recommended to prevent electrical shocks, assure safety of personnel and to reduce or eliminate down time. It helps to detect deterioration of insulation in order to schedule repair work such as: vacuum cleaning, steam cleaning, drying and rewinding. It is also helpful when evaluating the quality of the repairs before the equipment is put back into operation.

WHAT CAUSES INSULATION FAILURE?

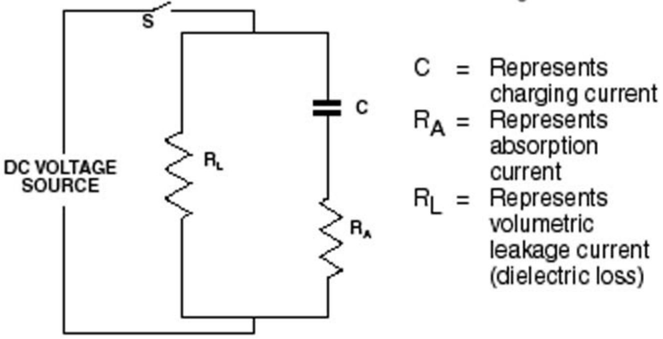
Some of the more common causes of insulation failure include: excessive heat or cold, moisture, dirt, corrosive vapors, oil, vibration, aging and nicked wiring. What tests are used to detect insulation deterioration? There are numerous maintenance tests for assessing insulation quality. The three tests discussed here are used primarily to test motor, generator and transformer insulation.

WHAT EQUIPMENT IS NECESSARY FOR CONDUCTING INSULATION RESISTANCE TESTS?

- Megohmmeter with a timed test function
- Temperature indicator
- Humidity meter (not necessary if equipment temperature is above the dew point)



Test Currents in Insulation One Line Diagram


S
C
R_L
R_A
DC VOLTAGE SOURCE
C = Represents charging current
RA = Represents absorption current
RL = Represents volumetric leakage current (dielectric loss)

TEST CURRENTS IN INSULATION

Total current in the body of the insulation is the sum of three components

- Capacitance Charging Current
- Absorption Current
- Leakage or Conduction Current

INSULATION RESISTANCE READINGS

Readings are time dependent

- at the start, capacitance is what you see first
- at or about one minute, absorption
- at 10 minutes, reading is mainly leakage current

These changing readings are best seen with analog bargraphs on digital instruments or needle movement on analog instruments.

SPOT READING TEST

METHOD

For this test, the megohmmeter is connected across the insulation of the windings of the machine being tested. A test voltage is applied for a fixed period of time, usually 60 seconds and a reading is taken. The spot reading test should only be carried out when the winding temperature is above the dew point. The operator should make a note of the winding temperature, so that it will be possible to correct the reading to a base temperature of 20°C.

TEST DURATION

To obtain comparable results, tests must be of the same duration. Usually the reading is taken after 60 seconds.

INTERPRETATION OF RESULTS

Proper interpretation of spot reading tests requires access to records of results from previous spot reading tests. For conclusive results, only use results from tests performed at the same test voltage for the same amount of time, and under similar temperature and humidity conditions. These readings are used to plot a curve of the history of insulation resistance. A curve showing a downward trend usually indicates a loss of insulation resistance due to unfavorable conditions such as: humidity, dust accumulation, etc. A very sharp drop indicates an insulation failure. See Figure 1.

Example of the variation of insulation resistance over a period of years:

At A, the effect of aging and dust accumulation is shown by decreasing values.

At B, the sharp drop indicates an insulation failure.

At C, the insulation resistance value after the motor has been rewound.

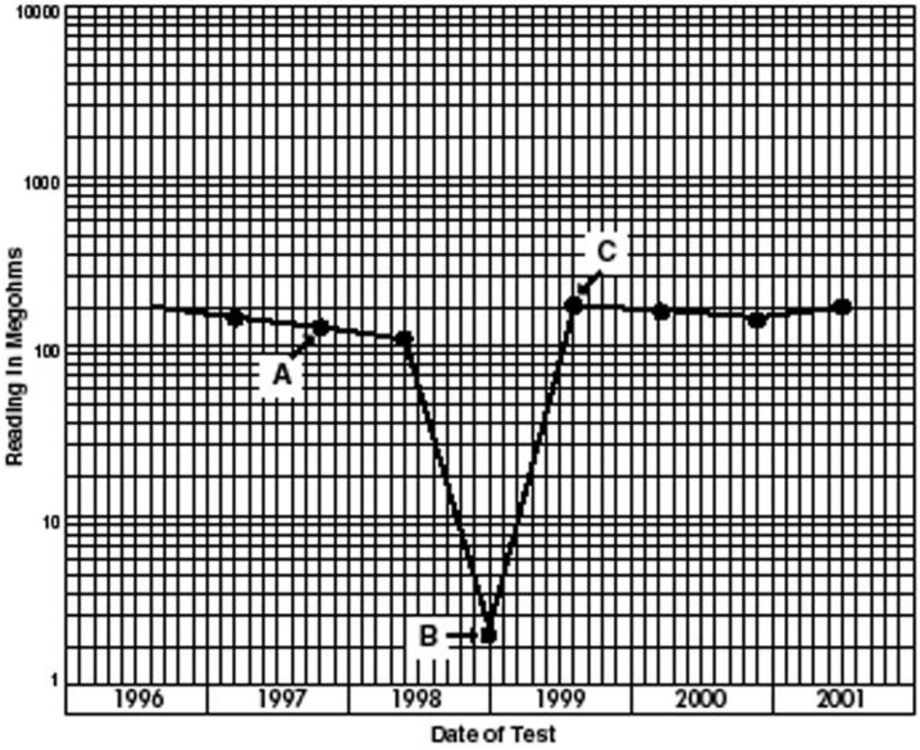


Figure 1

Dew point temperature is the temperature at which the moisture vapor in the air condenses as a liquid.

TIME-RESISTANCE TESTING METHOD

This method is fairly independent of temperature and often can give you conclusive information without records of past tests. It is based on the absorption effect of good insulation compared to that of moist or contaminated insulation. Simply take successive readings at specific times and note the differences in readings (see curves, Figure 2). Tests by this method are sometimes referred to as absorption tests.

Good insulation shows a continual increase in resistance (see curve D) over a period of time (in the order of 5 to 10 minutes). This is caused by the absorption; good insulation shows this charge effect over a time period much longer that the time required to charge the capacitance of the insulation.

If the insulation contains moisture or contaminants, the absorption effect is masked by a high leakage current which stays at a fairly constant value ? keeping the resistance reading low (R = E/I) (see curve E).

The time-resistance testing is of value because it is independent of equipment size. The increase in resistance for clean and dry insulation occurs in the same manner whether a motor is large or small.You can compare several motors and establish standards for new ones, regardless of their horsepower ratings.

Figure 2 shows how a 60-second test would appear for good and bad insulation. When the insulation is in good shape, the 60-second reading is higher that the 30-second reading.

A further advantage of this two reading test is that it gives you a clearer picture, even when a “spot reading” says the insulation looks ok.

Time-resistance tests on large rotating electrical machinery - especially with high operating voltage - require high insulation resistance ranges and a very constant test voltage. A heavy-duty megohmmeter serves this need. Similarly, such an instrument is better adapted for cables, bushings, transformers, and switchgear in the heavier-duty sizes.

Test Methods - Time-Resistant Tests Dielectric Absorption Ratio (DAR)

- The ratio of 60 seconds/30 seconds
- less than 1 = failed
- 1.0 to 1.25 = OK
- 1.4 to 1.6 = excellent
- Note: This is not a commonly used test

STEP VOLTAGE TEST

METHOD

In this test, the operator applies two or more test voltages in steps. The recommended ratio for the test voltage steps is 1 to 5. At each step, test voltage should be applied for the same length of time, usually 60 seconds. The application of increased voltage creates electrical stresses on internal insulation cracks. This can reveal aging and physical damage even in relatively dry and clean insulation which would not have been apparent at lower voltages.

TEST DURATION

A series of “steps”, each step lasting 60 seconds.

INTERPRETATION OF RESULTS

Compare the readings taken at different voltage levels, looking for any excessive reduction in insulation resistance values at the higher voltage levels. Insulation that is thoroughly dry, clean, and without physical damage should provide roughly the same resistance values despite changes in test voltage levels. If resistance values decrease substantially when tested at higher voltage levels, this should serve as a warning that insulation quality may be deteriorating due to dirt, moisture, cracking, aging, etc.

$$\text{Polarization Index (PI)} = \frac{\text{10-minute reading}}{\text{1-minute reading}}$$

The IEEE Std 43-2000 lists the following minimum values for the polarization index for AC and DC rotating machines:

Class A: 1.5 Class B: 2.0 Class C: 2.0

Absorption curve of test conducted on 350 HP Motor: Curve D indicates a good insulation with an excellent polarization index of 5. Curve E indicates a potential problem. The polarization index is only 140/95, or 1.47.

(2) IEEE Std. 43-2000, “Recommended Practice for Testing Insulation Resistance of Rotating Machinery.” Available from the Institute of Electrical and Electronics Engineers, Inc., 345 E. 47th St., New York, NY 10017.

BEFORE AND AFTER REPAIR:

Curve F shows a downward trend of insulation resistance values as the test voltage is increased. This indicates a potential problem with the insulation. Curve G shows the same equipment after it has been repaired.

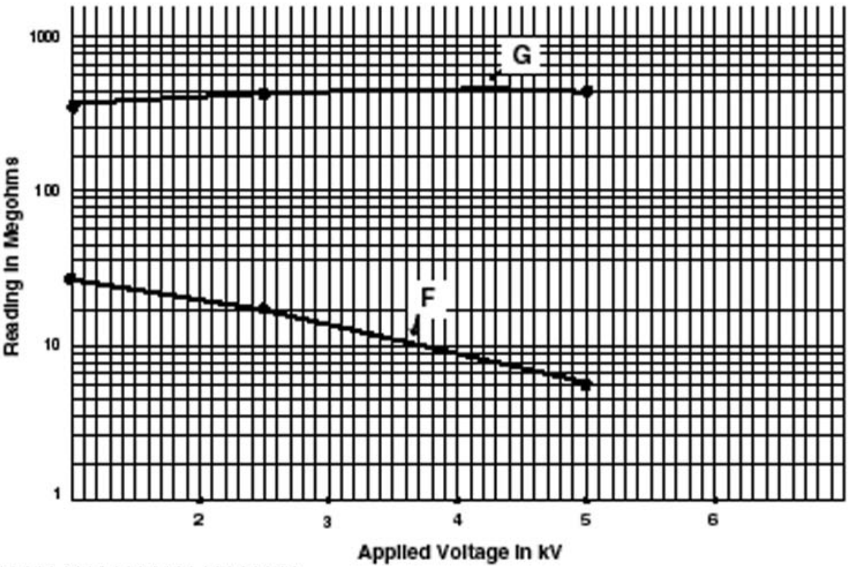
UTILIZING THE GUARD TERMINAL

The guard terminal is useful when measuring very high resistance values.

WHAT TEST VOLTAGE SHOULD I USE?

There are two schools of thought regarding the voltage to test insulation at. The first applies to new equipment or cable and can use AC or DC test voltages.

When AC voltage is used, the rule of thumb is 2 x nameplate voltage + 1000. When DC voltage is used (most common on megohmmeters manufactured today) the rule of thumb is simply 2 x nameplate voltage except when higher voltages are used. See chart below for suggested values.



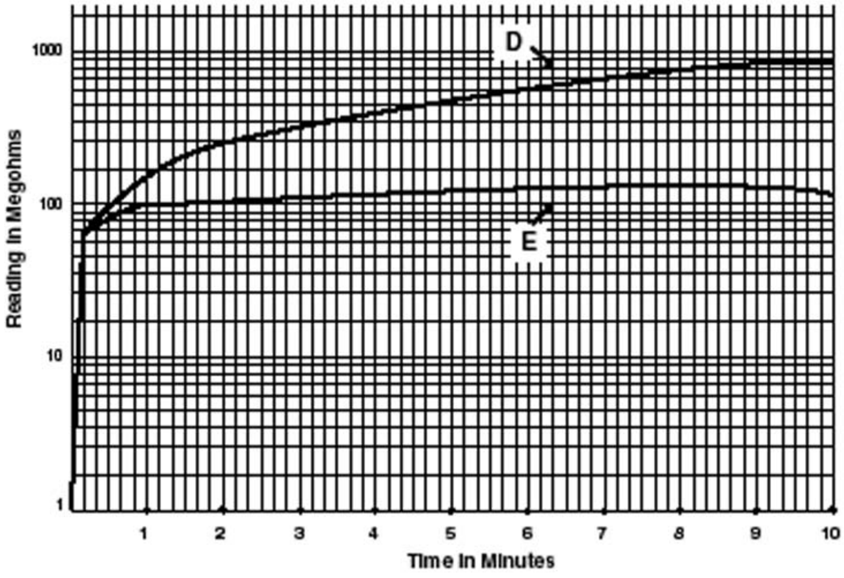


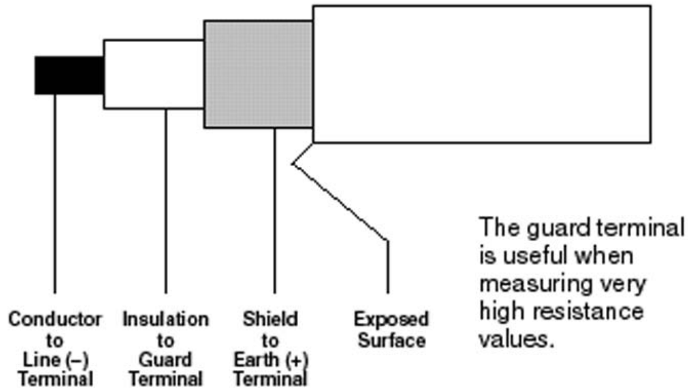
Figure 2

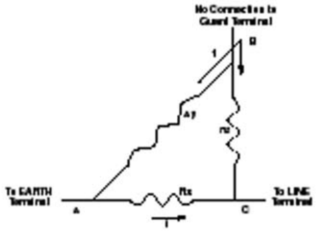
EQUIPMENT/CABLE RATING

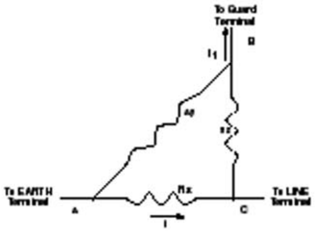
24 to 50V
50 to 100V
100 to 240V
440 to 550V
2400V
4100V

DC Test Voltage
50 to 100VDC
100 to 250VDC
250 to 500VDC
500 to 1000VDC
1000 to 2500VDC
1000 to 5000VDC

It is always advisable to contact the original equipment manufacturer to get their recommendation for the proper voltage to use when testing their equipment.


Conductor to Line (–) Terminal
Insulation to Guard Terminal
Shield to Earth (+) Terminal
Exposed Surface
The guard terminal is useful when measuring very high resistance values.





ADVANTAGES OF DC TESTING

- Lighter size and weight of test equipment
- Non-destructive
- Historical data can be compiled

TRANSFORMER TESTING

Transformers are tested at or above the rated voltage to be certain there are no excessive leakage paths to ground or between windings. These are conducted with the transformer completely disconnected from the line and load. However, the case ground should not be removed.

SINGLE-PHASE TRANSFORMER

The following 5 tests and corresponding wiring diagrams will completely test a single-phase transformer. Allow at least 1 minute for each test or until the reading stabilizes.

a. High-voltage winding to low-voltage winding and ground

b. Low-voltage winding to high-voltage winding and ground

c. High-voltage winding to low-voltage winding

d. High-voltage winding to ground

e. Low-voltage winding to ground

THREE-PHASE TRANSFORMER

The following 5 tests and corresponding wiring diagrams will completely test a three-phase transformer.

a. High-voltage winding to low-voltage winding and ground

b. High-voltage winding to ground with low-voltage winding to guard

c. High-voltage winding to low-voltage winding

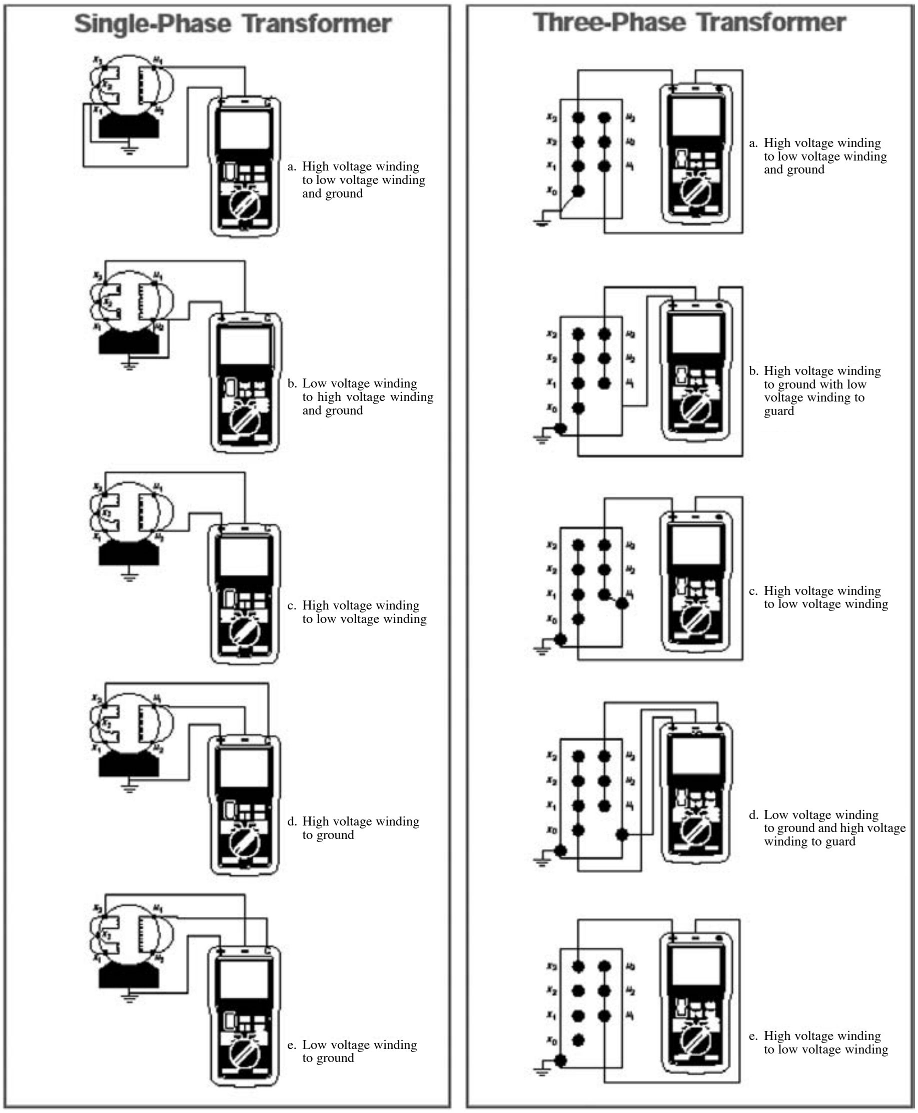
d. Low-voltage winding to ground and high-voltage winding to guard

e. High-voltage winding to low-voltage winding

+ = *Earth Terminal* **—** = *Line Terminal* **G** = *Guard Terminal*

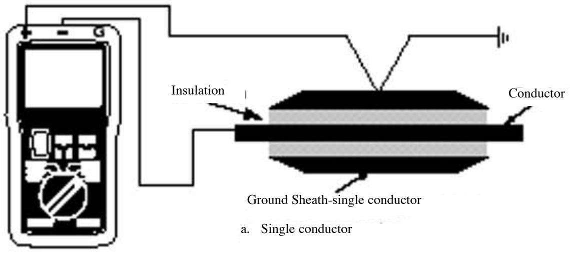
CABLE TESTING

Transformers are tested at or above the rated voltage to be certain there are no excessive leakage paths to ground or between windings. These are conducted with the transformer completely disconnected from the line and load. However, the case ground should not be removed.

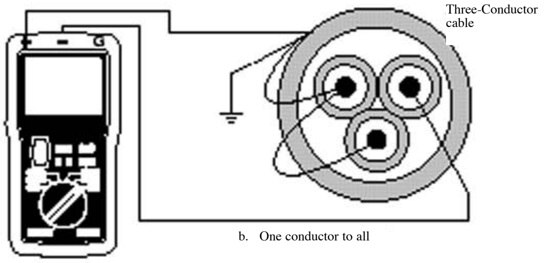

Single-Phase Transformer
a. High voltage winding to low voltage winding and ground
b. Low voltage winding to high voltage winding and ground
c. High voltage winding to low voltage winding
d. High voltage winding to ground
e. Low voltage winding to ground
Three-Phase Transformer
a. High voltage winding to low voltage winding and ground
b. High voltage winding to ground with low voltage winding to guard
c. High voltage winding to low voltage winding
d. Low voltage winding to ground and high voltage winding to guard
e. High voltage winding to low voltage winding

SINGLE CONDUCTOR

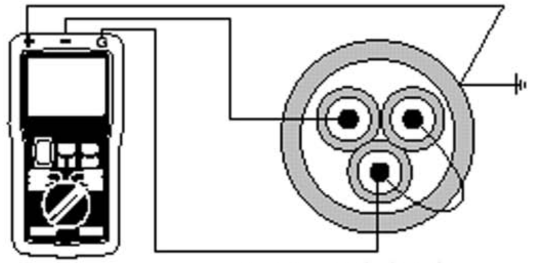
Connect as shown in the diagram
a. Conductor to Line (-) terminal and sheath to Earth (+)
Multi-Conductor
a. Single conductor
b. One conductor to all
c. One conductor to earth
d. One conductor to others minus ground



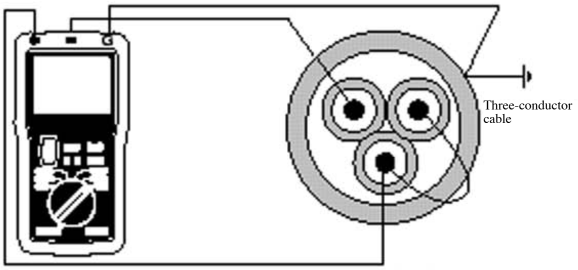
a. Single conductor



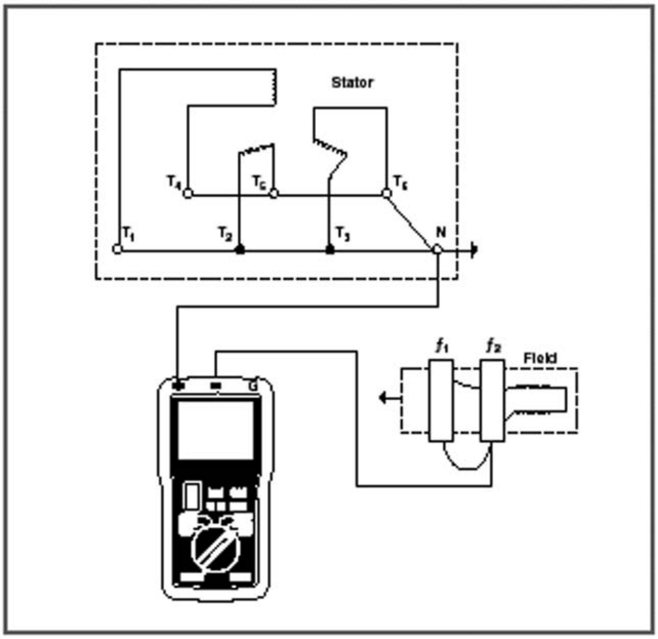
b. One conductor to all



c. One conductor to earth



d. One conductor to others minus ground



✚ = *Earth Terminal* ▬ = *Line Terminal* **G** = *Guard Terminal*

MOTOR AND GENERATOR TESTING

Before testing the above, lift the rotor brushes, ground the starter terminal and frame and ground the motor shaft. Discharge the field winding by grounding, then remove the field winding from ground and connect to the (-) Line connection on the megohmmeter. Connect the (+) Earth terminal to ground. The diagram shows the connection for testing the field insulation resistance. The stator winding may also be measured in a similar manner.

SUBSTATION LIFE CYCLE COST MANAGEMENT SUPPORTED BY STOCHASTIC OPTIMIZATION ALGORITHM

By Martin Hinow, ETH Zürich; Mark Waldron, National Grid; Dr. Lorenz Müller, ABB; and Heinz Aeschbach and Karsten Pohlink, AREVA T&D AG

SUMMARY

Life cycle cost (LCC) calculation is a major topic for substation management but often focuses upon the LCC of individual substation components rather than of the entire substation. However, effective substation management should take into account all potential cost influences including substation layout, substation maintenance, and substation failure.

Taking account of all such cost parameters creates a complex, multi-dimensional problem that can be better solved as by conventional techniques based on cost comparison of various fixed solutions. A new approach using cost optimization algorithms and sensitivity analysis is much better suited to this type of question.

This paper presents a method of applying an optimization algorithm to identify the lowest LCC substation management solution considering a wide range of possible combinations of all cost parameters. The optimization algorithm can also be used to explore sensitivities to particular variables.

The optimization algorithm can identify the substation solution with the lowest LCC and can provide information regarding those cost parameters which have the highest impact on the LCC result. The innovation of this idea is to utilize a single optimization algorithm to assess the LCC of the substation as a whole.

The use of the Genetic Algorithm (GA) to cater for all cost parameters will be described and a case study will be presented in support of the developed methodology. In the case study, aspects such as the level of penalty costs at which higher redundancy in the substation layout becomes cost effective, and the optimal nature of the redundancy will be identified and discussed. The case study will include the cost parameters of different switchgear technologies, and component failure probabilities such that a power utility could analyze where to insert redundancy into a substation to generate lower LCC.

1 INTRODUCTION

According to [1] the cost structure of high-voltage (HV) substation Life Cycle Cost (LCC) is broken down into Cost of acquisition CA(t), ownership CO(t) and renewal cost CR(t), see Figure 1 and equation (1). System cost of ownership is divided into scheduled, unscheduled maintenance and outage cost. A system failure results penalty cost for undelivered energy (including profit losses) and component replacement cost. The probability of an outage can be reduced by higher redundancy or by technologies with lower component failure probabilities.

There are huge possibilities for using redundant structures or installing different technologies in a substation layout. To find the substation with the lowest LCC, the cost of all possible layouts has to be calculated and to be compared. To avoid numerous calculations, an optimization algorithm has been

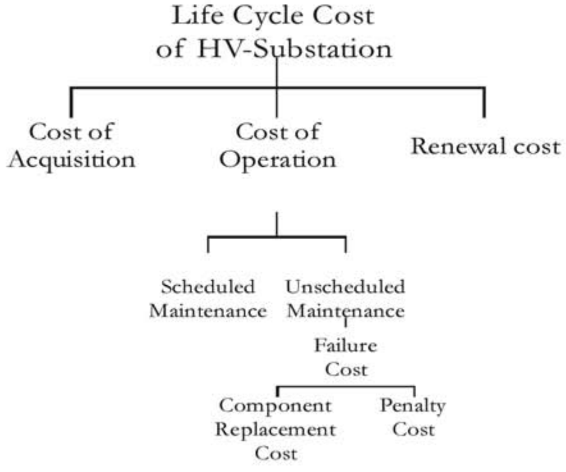


Figure 1: Cost composition scheme

exceeded which converges to the lowest LCC substation solution. This algorithm has to answer the questions “For what outage cost additional redundancy is useful and what are the optimum technologies and arrangements to be used?”

2 SWITCHGEAR EVOLUTION

The paper contains the following detailed life cycle cost structure. The life cycle cost CLC(t), as presented in the introduction, is given by:

$$C_{LC}(t) = C_A(t) + C_O(t) + C_R(t) \text{ , (1)}$$

The operation cost CO(t) can be calculated by:

$$C_O(t) = C_M(t) + C_F(t), \text{ (2)}$$

where CM(t) is the maintenance and CF(t) is the failure cost.

The failure cost CF(t) itself is a summation of component replacement cost CCR(t) and penalty cost for undelivered energy CP(t), see equation:

$$C_F(t) = C_{CR}(t) + C_P(t), \text{ (3)}$$

The component replacement cost CCR(t) is influenced by the component replacement price CRep,i of all n components and the individual i-th component failure probability Fi(t), see equation:

$$C_{CR}(t) = \sum_{i=1}^{n} C_{\mathrm{Re}\,p,i} * F_i(t) \text{ , (4)}$$

A system outage provides penalty cost and profit losses for energy not supplied. The penalty cost CP(t) can be calculated by using a time or an energy-dependent approach. This paper uses a timedependent penalty cost factor Kp which has to be multiplied with the system failure probability FS(t) and the system repair time tSRep. The penalty cost factor Kp is defined in this case as cost per outage time. The value of the factor Kp refers in this paper to a time period of 24 hours. Redundancy mainly influences the system failure probability. The system repair time is affected by several factors, including the number of repair teams and the component repair times, [3]. The factor Kp also takes into account profit losses during the outage

$$C_p(t) = K_p * F_s(T) * t_{S,Rep}, \text{ (5)}$$

Maintenance activities can be differentiated as scheduled and unscheduled maintenance. The cost of both can be calculated with the following equation

$$C_M(t) = \sum_{i=1}^{n} \sum_{j=1}^{m} C_{i,j}(t) \text{, (6)}$$

where Ci,j is the cost of the individual component maintenance activity, n refers to the component and m refers the corresponding maintenance activity.

3 METHODOLOGY OF THE GENETIC ALGORITHM

The goal is to find a methodology to minimize the LCC of a substation. The equations show that the LCC calculation model is component specific, meaning that the optimization problem is discrete.

Another very important fact is that the failure cost is influenced by stochastic terms, e.g. the system or component failure probability. Discrete and stochastic problems can be solved by stochastic optimization algorithm such as the Genetic Algorithm (GA), [4].

The main idea of GA is to find in an iterative way an optimized substation solution. The algorithm changes the components in the substation layout, as in Figure 2 varying both the technology and the type of redundancy. Every component is defined with its LCC-parameters, which includes

- acquisition cost;
- maintenance cost;
- all parameters of the component hazard curve;
- component replacement time; and
- the parameters of different maintenance strategies.

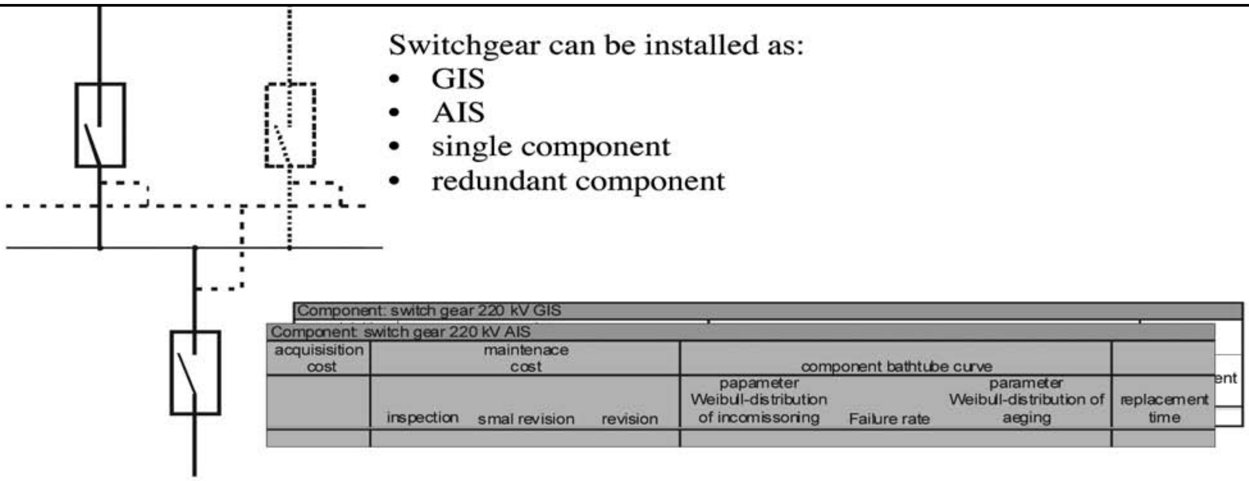

Switchgear can be installed as:
• GIS
• AIS
• single component
• redundant component
Component: switch gear 220 kV GIS
ent
Component: switch gear 220 kV AIS
acquisisition cost
maintenace cost
component bathtube curve
inspection
smal revision
revision
papameter Weibull-distribution of incomissoning
Failure rate
parameter Weibull-distribution of aeging
replacement time

Figure 2: Substation parameters

All parameters are put into in a component specific file card, see Figure 2. In each iteration step the algorithm calculates the LCC for the current substation solution and for the next iteration step the algorithm improves the substation with the following aspects [4]:

- taking over the best substation solution;
- combination of low LCC substation layout to find better substation solution; and
- stochastic variation of substation layouts to find better substation solution.

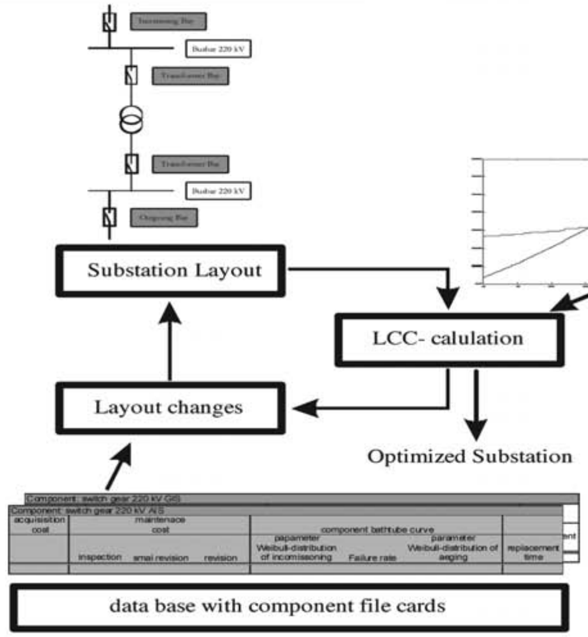


Figure 3: Algorithm principle

The principle of the iterative algorithm is described in Figure 3. The simulation starts with the initial substation determined by the user. Every iteration step has the task of a LCC calculation of the substation and layout changes. The life cycle cost calculation bases on the equations (1)-(6). The calculation step provides for each substation solution a LCC value. The best substation (lowest LCC) will be taken over into the next iteration step. The other solutions will be modified according to the listed principles. Thereby a data base contains all component file cards and provides the components to the algorithm. The algorithm replaces the components on there corresponding place in the corresponding layout. The algorithm changes in this step the component redundancy. After a certain number of iteration steps (which has to be chosen by the user) the algorithm provides the optimal composition of the substation solution.

The algorithm has been designed using MATLB software.

4 SIMULATION

A case study has been performed to demonstrate the suitability of the developed algorithm. An initial substation layout has been defined, see figure 4. Different penalty cost factors have been assumed. For each penalty cost factor a simulation was carried out find the LCC optimized substation layout. The goal of the investigation was to figure out the influence of the penalty cost on the optimized substation layout.

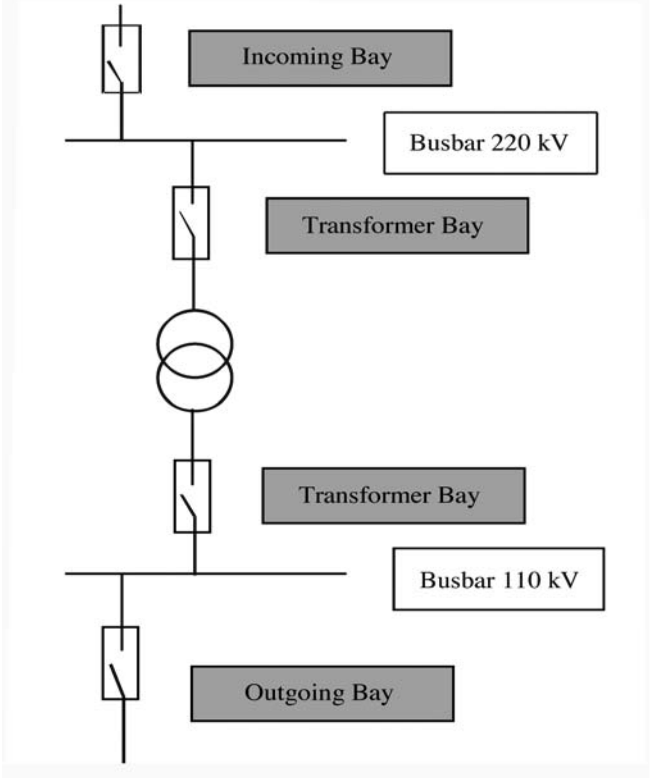


Figure 4: Simulation layout

The cases study deals with the following components:

- Incoming 220 kV bay;
- 220 kV bus bar;
- Power transformer bay 220 kV;
- Power Transformer, 220 kV / 110 kV;
- Power transformer bay 110 kV;
- Bus bar 110 kV; and
- Outgoing bay 110 kV.

The busbars and bays can be executed in GIS or AIS technology. All components can be installed as single, redundant or multi redundant components.

4.1 ASSUMED INPUT DATA

The case study required all listed input data. Failure data, replacement times or maintenance data for certain components are provided by the listed [8] statistics. Reference values of investment cost are not readily available and are quite difficult to estimate because they are strongly dependent upon local parameters. However, since the goal of this study was to demonstrate the developed methodology, it was adjudged that calculations with roughly estimated date was sufficient. For reason of transparency, all cost parameters have been used as relative values. Utilities who have all detailed cost data can insert them, the methodology is unmodified.

4.2 INVESTMENT COST

The definition of all investment cost includes secondary equipment and land cost since both items are related to the component cost. One bay of 220 kV GIS-technology is defined with 100 percent points.

All the other equipment refers to this value. Regardless of indoor or outdoor substation, the ratio between GIS- and AIS-bay of the same voltage level can be assumed to be approximately one to zero point nine. The ratio between the bay of the 220 kV and 110 kV level has been assumed to be one to zero point six [5]. The range of the investment cost ratio between switchgear and a power transformer is wide because of complexity of price influencing factors. In this paper the ratio has been assumed to be one to three for a 220 kV GIS bay and a typical range 50 MVA Power Transformer [6].

4.3 Maintenance cost

Substation maintenance cost is marginal in comparison with investment cost. While the plant investment cost is in the order of millions of dollars, the scheduled maintenance cost has

Component	Investment cost in percent	
	220 kV	110 kV
Bay GIS	100	60
Bay AIS	90	50
Bus bar GIS	20	12
Bus bar AIS	18	10
Power Transformer	300	

Table 1: Investment cost

Component	Investment cost in percent	
	220 kV	110 kV
Bay GIS	100	60
Bay AIS	90	50
Bus bar GIS	20	12
Bus bar AIS	18	10
Power Transformer	300	

Table 2: Maintenance activities
*Maintenance activities, which are related only to the bus bar have not been identified

Component	Investment cost in percent	
	220 kV	110 kV
Bay GIS	100	60
Bay AIS	90	50
Bus bar GIS	20	12
Bus bar AIS	18	10
Power Transformer	300	

Table 3: Failure rates
*Value of the power transformer is failure per 100 transformer years

been assessed in a range of only thousands of dollars [6]. The simulation considers for the power transformer as well as for the other substation components inspections and reconditioning. The schedule for all AIS components is taken from [6].

The schedule for the GIS components is taken from [7]. The data is summarized in Table 2.

4.4 FAILURE RATES

Component failure rates of the GIS and AIS components are taken from [8]. The failure rate of the power transformer and the component replacement times has been estimated. The key factors were that the power transformer has a failure rate in the same range as an AIS-bay and the replacement of the GIS-bay takes double time in comparison with an AIS-bay. All data is summarized in Table 3.

The cost calculation has been made assuming a lifetime for all substation components of 40 years. Three simulations have been run and the following daily penalty (see equation 5) cost factors have been taken in account:

- K_P =10;
- K_P =100;
- K_P =1000.

The values have to be seen as examples. The goal of the investigation is to show the influence of the penalty cost factor on the optimal system layout. The third penalty cost factor seems to be very high in comparison with the component investment cost of a substation but this extreme value can be used to cater for cases where interruption of supply cannot be accepted.

5 RESULTS

Figure 5 shows the convergences of the developed algorithm of all three simulations. The simulation with the lowest penalty cost factor (shown with INSERT TRIANGLE) resulted in the lowest substation LCC and, conversely, the simulation with the highest penalty cost factor (shown with INSERT BLACK SQUARE) results in the highest substation LCC. Both extreme results are dominated by the investment strategies of the substations.

Regardless of the absolute value of the penalty cost factor, and as expected, increasing penalty costs result in a greater necessity for reduction of the system failure probability. The consequence of this is to install redundant components leading to a higher investment cost. The cost development over 40 years service is pictured in Figure 6.

The simulation with the lowest penalty cost factor of KP = 10 yields out the most simple layout, consisting of only single components of AIS-technology (see Figure 7a). The low penalty cost factor requires the lowest system failure cost of the three cases.

The simulation with the penalty cost factor of KP = 100 provides a layout quite similar to the lowest penalty case, consisting of single components but utilizing GIS-technology (see

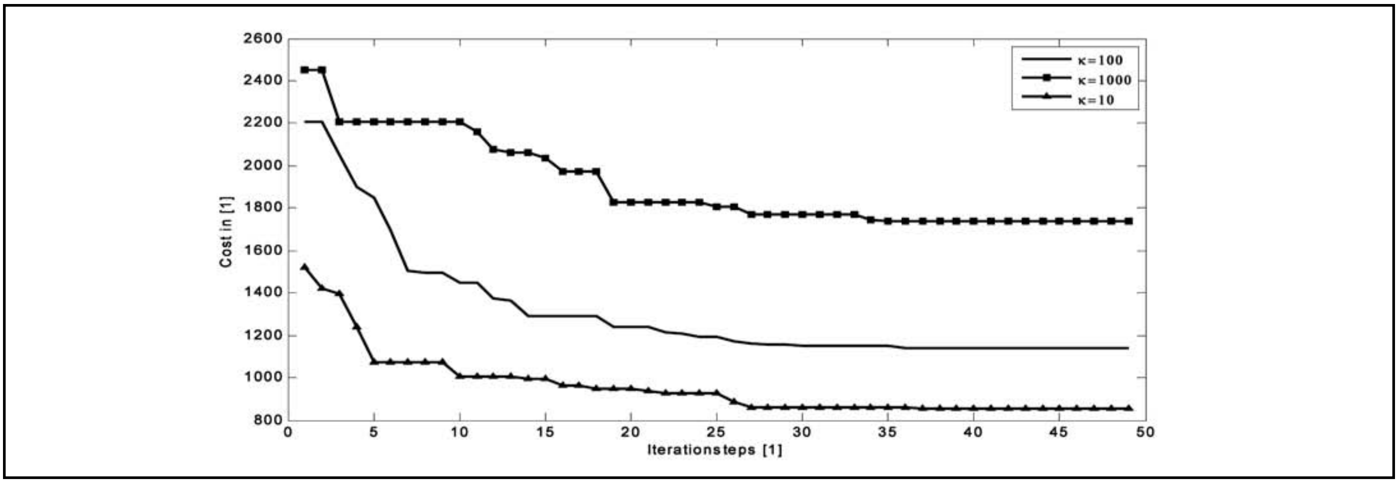


Figure 5: LCC evolution with three different penalty cost factors

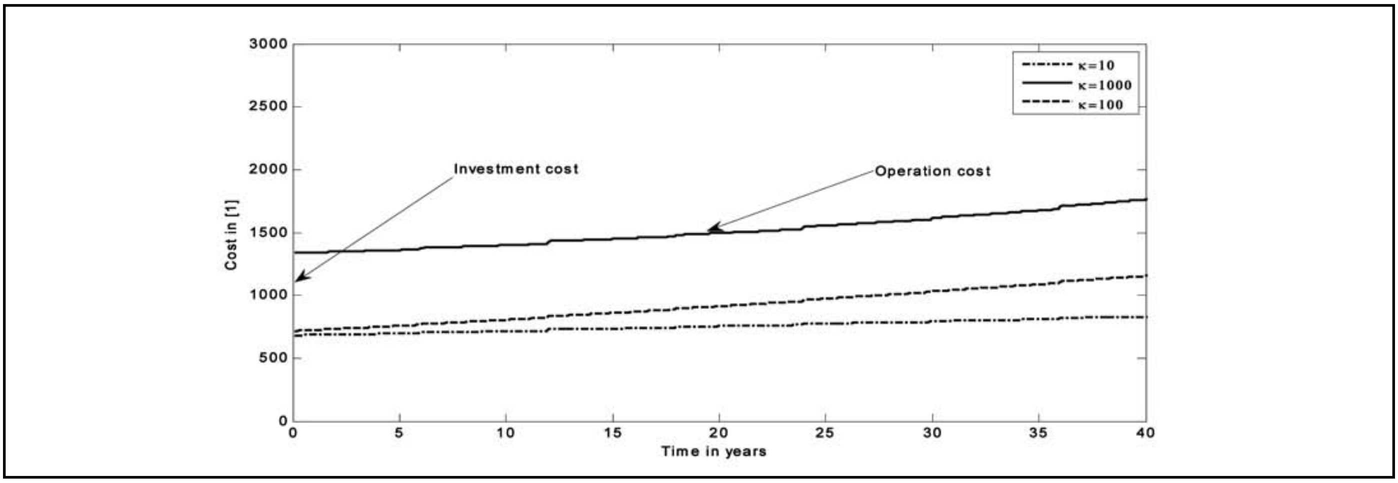


Figure 6: LCC over 40 years

Figure 7b). The higher investment cost of the GIS components compensates the higher penalty cost with the lower failure rate. The algorithm figures out that the investment strategy with GIS components is the optimum for the pictured case.

The last simulation with the highest penalty cost factor provides a substation with redundant power transformers and redundant bays on the upper and lower voltage levels (see Figure 7c). The bus bar having the lowest failure rate remains as a single component.

To verify the result, a LCC comparison between the second and the third layout has been done. Using a penalty cost factor KP = 1000 for both layouts shows that the redundant GIS-layout generates higher investment cost, but because of the lower failure probability, the redundant layout provides lower failure cost, and 15 years operation time is much more economical than the single GIS-layout, see Figure 8.

The influence of other redundancies of S/S components would be modeled in the game way.

CONCLUSIONS

An innovative approach has been developed and applied to find the LCC optimized layout and technology of a particular substation. Simulations show the suitability of the developed algorithm. For all cases, the investment cost dominates the LCC of a HV-substation however, for high penalty cost scenarios, the failure cost also has a significant impact on the LCC. The developed algorithm responded to this increasing penalty cost by converging on a layout with higher levels of redundancy, utilizing more reliable technology. The algorithm presented here forms the basis of a technique for utilities to identify the optimum investment and maintenance strategy providing that they have access to the appropriate reliability and cost data.

One simulation using the described tool provides all cost relevant substation solutions, also alternative substation solutions which are close to the global cost minimum. The algorithm can be used as an assisting tool to design LCC optimized substations. It can be extended to consider the application of

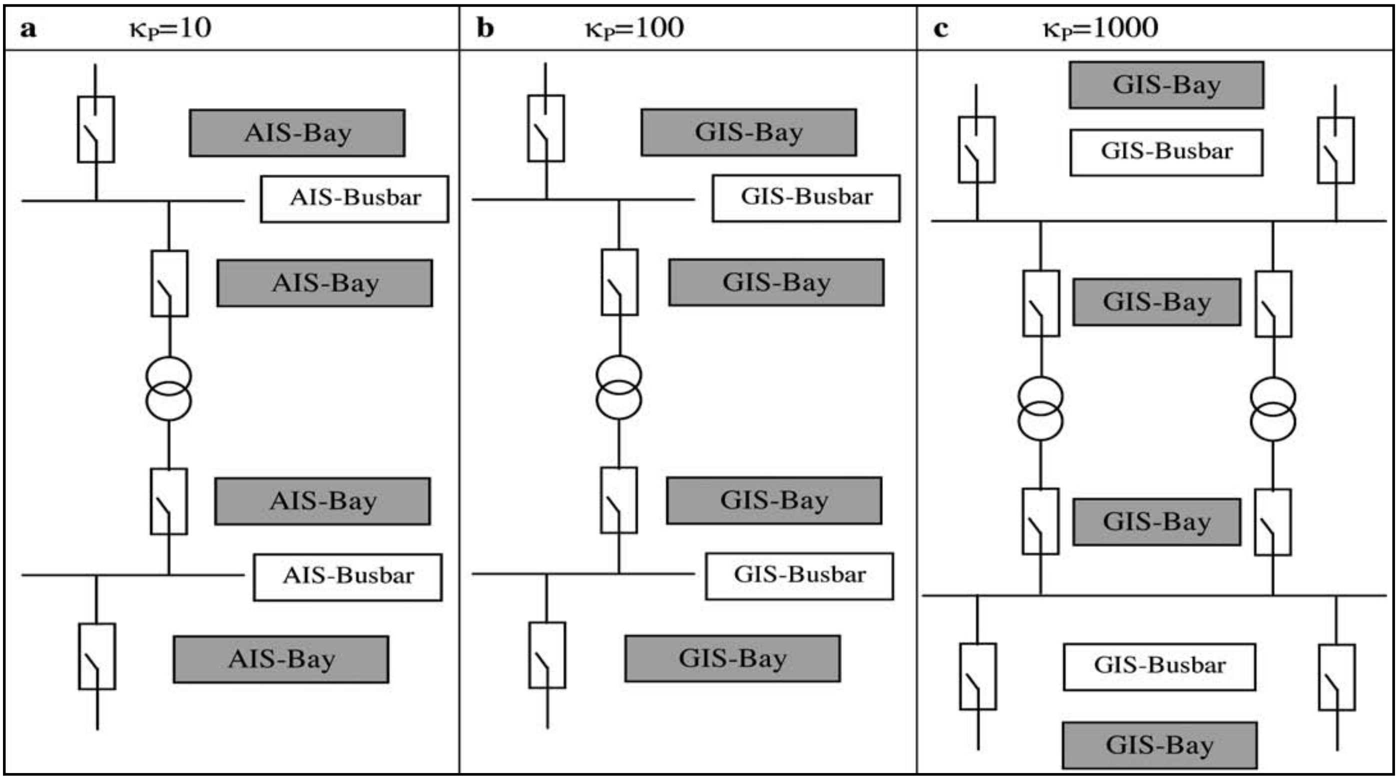


Figure 7: Layout optimization based on penalty cost factors

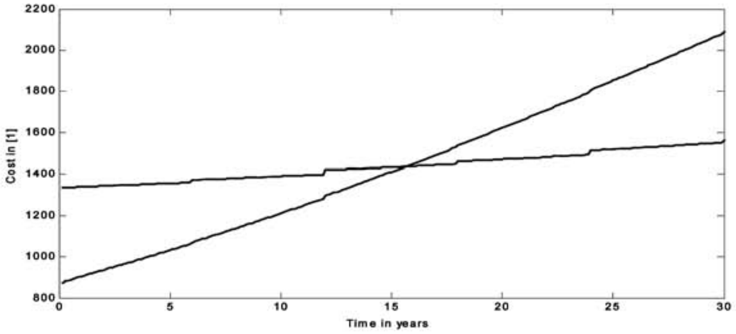


Figure 8: LCC comparison between single and redundant bay layout

advanced switching technologies as well.

ACKNOWLEDGEMENT

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THE CARE AND FEEDING OF A SYNCHRONOUS MOTOR

GE Motors

INTRODUCTION

The synchronous motor is a very useful dependable type of motor drive with wide application in industry.

However, because the synchronous motor is seldom used in the small horsepower range, many who feel quite familiar with the induction motor because of their experience with the smaller drives, become uneasy when faced with installing a synchronous motor on their system.

The synchronous motor is quite similar to the induction motor in its general arrangement, although, usually the synchronous motors are either very large in rating, or quite low in speed relative to the normal induction motor.

Typically, the synchronous motor has a short core length and large diameter when compared with the induction motor.

GENERAL PRINCIPALS OF OPERATION

Polyphase synchronous motors have stators and stator windings (armature windings) essentially similar to those of induction motors. As for the polyphase induction motor, currents circulating through the distributed stator winding produce a flux pattern of alternate north and south poles that progresses around the air gap at a speed directly proportional to the frequency of the power supply and inversely proportional to the number of pairs of poles in the winding.

The rotor of the synchronous motor differs considerably from the induction motor rotor. The rotor has salient poles corresponding to the number of stator winding poles.

During normal steady-state operation, there is no average relative motion between rotor pole and the stator flux pole; therefore, there can be no voltage induced in the rotor by mutual flux and hence excitation cannot come from the AC line. Instead, the poles are wound with many turns of copper wire, and when a direct current is circulated through the winding, they become alternately north and south magnetic flux poles. Until the early 1960s the DC excitation had to be applied to the field through the brush rigging and slip rings. However, today, as an alternative, a brushless excitation system with SCR control is frequently used.

Should the rotor be at standstill when direct current is applied to the field winding, the interaction of the stator flux and the rotor flux will provide a large oscillating torque, but the rotor cannot accelerate. To start a synchronous motor then, it is necessary to embed a number of bars in the face of each pole and short circuit these bars at each end to form a squirrel-cage similar to that found in the induction motor. Further, the field winding must be disconnected from the DC supply and shorted, usually through an appropriate resistor or the Brushless Exciter circuit. By proper design of the size, material, and spacing of the bars in the squirrel-cage (often called “amortisseur” or “damper” winding), sufficient induction motor-type torque is developed to accelerate the rotor to nearly full load speed.

If the rotor has reached sufficient speed and then direct current is applied to the field winding, the motor will pull into step with the rotating stator flux. The pull-in torque of a synchronous motor is the maximum constant load torque against which the motor will pull its connected inertia load (WK2) into synchronism when rated DC field excitation is applied.

The average pull-in torque is a function primarily of the squirrel-cage winding characteristics; however, the secondary effect of the external shorting resistor and field winding resistance make important contributions to the speed attainable on the squirrel-cage winding with a given load torque applied to the motor. Because of the salient pole effect, the instantaneous pull-in torque varies somewhat from the average value depending upon the angle between the axes of the rotor and stator poles.

There are differences in control and motor protection of the synchronous motor which are related, of course, to the rotor construction. Since the DC excitation is a necessity for synchronous operation, and synchronous operation is fundamental to the synchronous motor, protection against loss of field and loss of synchronism should be provided.

During start, the control equipment must automatically and accurately ensure that the rotor speed has reached a proper value and further, in many cases, ensure that the proper angle between rotor and stator flux exists before the DC excitation is applied. Inasmuch as the synchronous motor squirrel-cage winding needs only accelerate the total WK2 and load, not provided the load torque continuously, the synchronous rotor's thermal capability, and, hence its stall time are generally much less that for an induction motor and special protection for the squirrelcage must be provided.

However, since the synchronous motor stators and stator windings, bearings, and enclosure variations are essentially the same as the induction motor, protection schemes for these parts are basically the same.

WHY SYNCHRONOUS MOTORS

Economy lies behind the use of synchronous motors in many of the applications of this type motor in industry.

The five most common reasons for specifying synchronous motors are:

1. To take advantage of lower first cost
2. To obtain the inherent high efficiencies
3. To obtain power factor correction
4. To obtain special starting characteristics
5. To obtain special synchronous characteristics

Of these five advantages, the first four have a direct bearing on the over-all cost of plant operation.

LOWER FIRST COST

Generally speaking, the cost of a synchronous motor with exciter and control may well prove less than that of any other AC motor if the horsepower rating is equal to or greater than twice the rpm. Of course, it is impossible to draw a definite dividing line because various electrical and mechanical modifications (as well as control requirements) enter into the evaluation.

HIGH EFFICIENCY

Although the saving in first cost may be substantial, in many cases even greater savings can be realized from the lower operating costs of the synchronous motor. When motor efficiency becomes the primary consideration in choosing a motor, a 1.0 P.F. Synchronous motor is usually the solution. Since no KVAR is required, only real power, the line current is a minimum, resulting in less I2R loss in the motor armature (stator) windings. Also, since the field current required is at the practical minimum, there is less I2R loss in the rotating field winding as well. Special high-torque situations excepted, the lower losses in both the armature and field permits synchronous 1.0 P.F. ratings to be built in smaller frames than corresponding 0.8 P.F. synchronous in induction ratings.

Thus, the resulting 1.0 P.F. synchronous motor efficiencies are generally higher than induction motor efficiencies for corresponding ratings. Figure 1 shows standard full load efficiencies for typical high speed 1.0 and 0.8 P.F. synchronous and squirrel-cage induction motors as well. Figure 2 is the same display for low-speed motors.

POWER FACTOR CORRECTION

Most power rates are based not only on the real power in KW delivered, but also on the power factor at which it is delivered. A penalty charge is made when the power factor is lower than a specified value (usually between 0.97 and 0.9 power factor). This is because a low power factor indicates an increase in reactive kilovolt amperes (KVAR) required and, consequently, an increase in the size of associated generating and transmission equipment.

Industrial plants generally have a predominance of lagging power factor loads such as smaller or lower-speed induction motors which require considerable amounts of KVARs in magnetizing (exciting) current. Although it is possible to use capacitors to supply the needed KVARs, if there is an opportunity, it is often preferred to use synchronous motors for this purpose. Because of their separate source of excitation, synchronous motors can either increase the KW base without requiring any additional KVARSs (the unity P.F. motor) or, not only increase the KW base but also supply the needed KVAR's as well (0.8 power or over-excited motor).

Curves shown in Figure 3 indicate the amount of corrective KVARSs provided by both 1.0 and 0.8 P.F. motors when excitation is held constant and the hp (kw) required from the

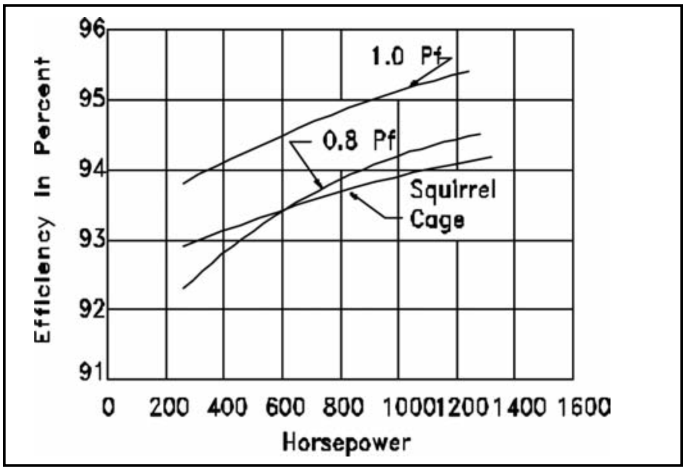


Figure 1. Typical Full Load Efficiencies, High Speed Motors

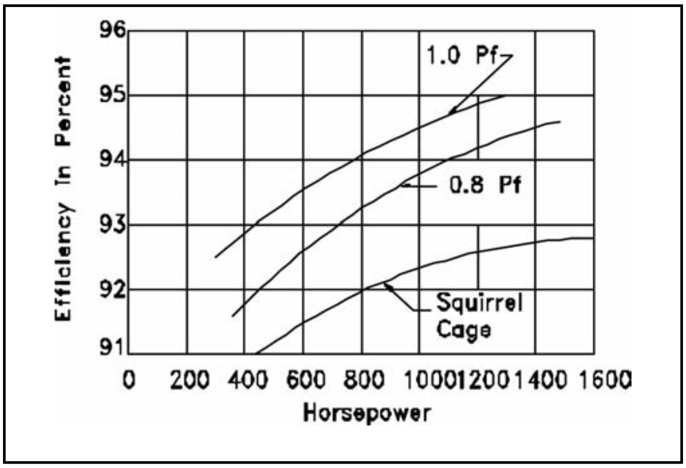


Figure 2. Typical Full Load Efficiencies, Low Speed Motors

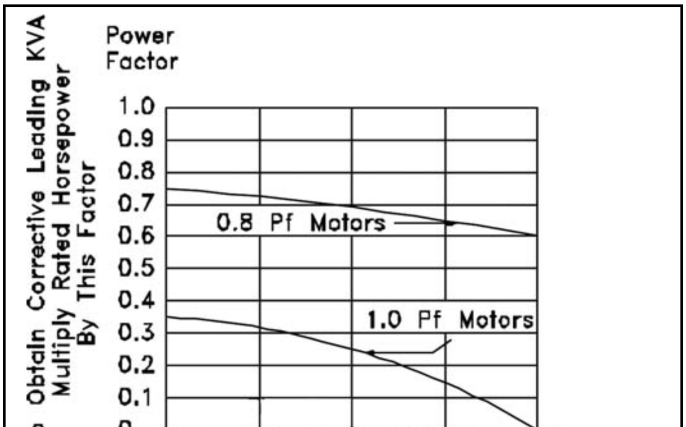


Figure 3. Variation of Reactive KVA with Load

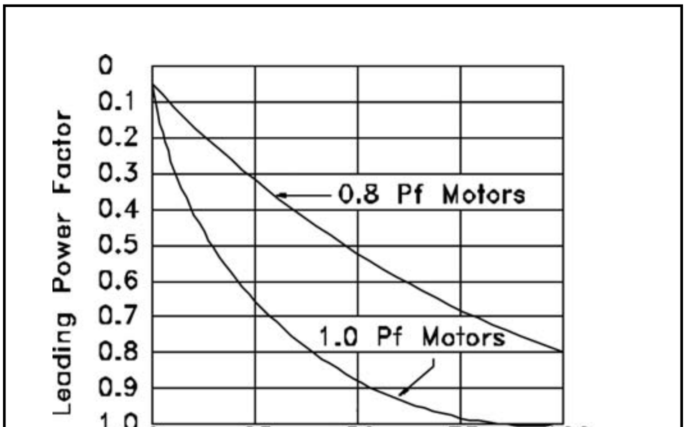


Figure 4. Variation of Power Factor with Load

motor by the load is decreased. Figure 4 displays curves showing how the power factor decreases when excitation is held constant and the required horsepower is decreased.

Thus, it is apparent that the synchronous motor can, in many instances, provide the user with the welcome reduction in power rates while providing the necessary drive horsepower.

SPECIAL STARTING CHARACTERISTICS

Usual requirements during the starting cycle may often best be met by synchronous motors because combinations of special high or low torques and low inrush current can be furnished without appreciably affecting the operating characteristics at rated speed.

High torques, for example, are often required on large ball mill drives for ore crushing service. Starting torques between 150 to 200 percent of full load torque are often required for large ball mill drives. Although normal starting torque for a low-speed motor is only 40 percent of full-load torque, special design, which affects primarily the amortisseur or starting winding (and somewhat the machine physical dimensions), can build special high torques into the motor. Yet, since the starting winding is principally affected, normal operating efficiency remains only slightly decreased. A corresponding increase in induction motor torques would be prohibitive.

Low inrush current at starting is often desirable because of power systems requirements. Some means of reduced voltage starting will always be available, but always at the expense of starting torques in addition to the extra expense for the control equipment. Often times, sufficiently low inrush can be obtained by special design of the motor stator and amortisseur winding. In some cases, it is possible to lower line currents at starting by about 1/3 and still maintain the desired torques. However, it must be pointed out that applications involving high starting and pull-in torques and/or high inertia loads require motor designs which at best have considerably higher than normal starting current.

SPECIAL SYNCHRONOUS CHARACTERISTICS

Constant Speed - Since the magnetic poles produced by the direct current applied to the field winding are locked by magnetic attraction to corresponding rotating (constant speed) magnetic poles produced by the stator armature winding, the rotor turns at a constant average speed. This is true regardless of the load applied to the motor or as long as the load stays within the pull-out torque limitations of the motor. And not only will the synchronous motor maintain speed during overload, but it will also hold during voltage dips (again within specified overload torque limits).

Large Air Gap - Synchronous motors inherently have a much larger air gap, at least twice that of the induction motor. This is often an advantage for mechanical reasons.

The larger air gap also permits larger stator slots - an advantage when high voltage may be required.

BASIC CONSTRUCTION DIFFERENCES
HIGH-SPEED MOTORS

Synchronous motors are separated into high-speed and low-speed classifications because of the basic differences in rotor construction methods. The high-speed motor, nominally 500 rpm and above (see Figure 5) is characterized by its relatively long axial length in comparison with its rotor diameter. The higher rotating speeds, and consequently large centrifugal

High Speed Synchronous Motor Speeds

Poles	60 Hz r/min	50 Hz r/min	25 Hz r/min
4	1800	1500	750
6	1200	1000	500
8	900	750	--
10	720	600	--
12	600	500	--
14	514	--	--

Figure 5

Low-Speed Synchronous Motor Speeds

Poles	60 Hz r/min	50 Hz r/min	25 Hz r/min
8	--	--	375
10	--	--	300
12	--	500	250
14	514	428.5	215
16	450	375	187.5
18	400	333.3	168
20	360	300	150
22	327	272.7	137
24	300	250	125
26	277	230	115
28	257	214	107
30	240	200	100
32	225	187.5	94
36	200	166.7	84
40	180	150	75

Figure 6

forces, require the rotor spider to be built from high-strength steel laminations with punched or, occasionally, machined dovetail or tee-tail slots to receive the projecting matching piece from the pole and, thus, to fasten the pole assemblies to the motor.

Standard construction includes stator, rotor, shaft, and two bearings. For small and medium motors, the bearings are housed in end shields which are bolted to and become an integral part of the motor. These motors are open and self-ventilated. Some motor manufacturers' standard lines are drip proof as well.

LOW-SPEED MOTORS

The low-speed synchronous motor has inherently short core length relative to rotor diameter, that tends to make the end-shield construction in all ratings impractical. The rotor on the low-speed machine consists normally of a fabricated steel rim, spider assembly, and hub with the poles fastened to the rim by means of bolts. Special construction of the spider is possible including the split hub only, or the completely split rotor, often useful in compressor applications where there is driven equipment on each end of the drive shaft. The low-speed motor consists of a rotor and stator, shaft, bearings, bearing pedestals, coil guards, collector rings, brush rigging and support, and non-self-supporting base. Shaft, bearings, bearing pedestals and base may be omitted for such applications as compressor drives. These motors, termed "engine type" are provided with foundation caps (sole plates) and, of course, are furnished at considerably less cost to the user. See figure 6.

TORQUES AND INERTIA

Every synchronous motor must be designed with three different load torque conditions in mind:

1. Starting torque to breakaway the load from rest.
2. Pull-in torque to accelerate the load to a speed from which the application of DC field will pull it into synchronism.
3. Pull-out torque to keep momentary overload from pulling motor out of synchronism when a prescribed momentary overload is imposed.

In addition, certain applications such as ball mills require that the designer consider the load torque the entire acceleration period. This is to ensure that the motor develops sufficient torque to overcome the torque peaks such as the cascade torque which may occur at some speed part way between starting and the pull-in speed.

Standard torques which vary depending upon motor rating, power factor, and speed are tabulated in Figure 7.Although the synchronous motor operates with the DC field of the rotor locked in with the rotating mmf in the stator, it starts and accelerates by virtue of its amortisseur, or squirrel-cage, winding which functions by the same principals as the induction motor. Thus, the starting torques and the pull-in torque (discussed below) vary as the square of the applied voltage, and the starting current varies directly as the voltage as is the case with the induction motor.

The pull-in torque is defined as the maximum constant load torque against which the motor will pull its connected inertia (WK2) load into synchronism when field excitation is applied. Since the synchronous motor starts as an induction motor, it will accelerate to the point where the motor torque just equals the torque required by the load.

Usually this point is at 95 percent speed or greater (see Figure 8). Now, if the DC field is applied at the proper point, the rotor will "pull-in" by accelerating, in a fraction of a revolution, the combined WK2 of the motor rotor and the load to precisely synchronous speed.

Standard Synchronous Motor Torque Ratings

Horsepower Rating	60 Hz r/min	Percent of Full Load Torque		
		Locked-rotor	Pull-in #	Pull-out
For 1.0 Power Factor Motors				
1-200	514-1800	100	100	150
250-1000	514-1800	60	60	150
1250 and larger	514-1800	40	60	150
All ratings	450 and below	40	30	150
For 0.8 Power Factor Motors				
1-150	514-1800	100	100	175
200-1000	514-1800	60	60	175
1250 and larger	514-1800	40	60	175
All ratings	450 and below	40	30	200

Based on Normal Inertia ratings and rated excitation applied

Figure 7

The ability to accelerate the WK2 (that is, "pull-in" to synchronism) is limited for a given motor. It becomes apparent, then, that for large values of WK2, the amortisseur winding must bring the WK2 to a higher speed than for small WK2. To design for this requires that the value of load torque be accurately known so that the speed-torque capability of the amortisseur winding can be properly designed.

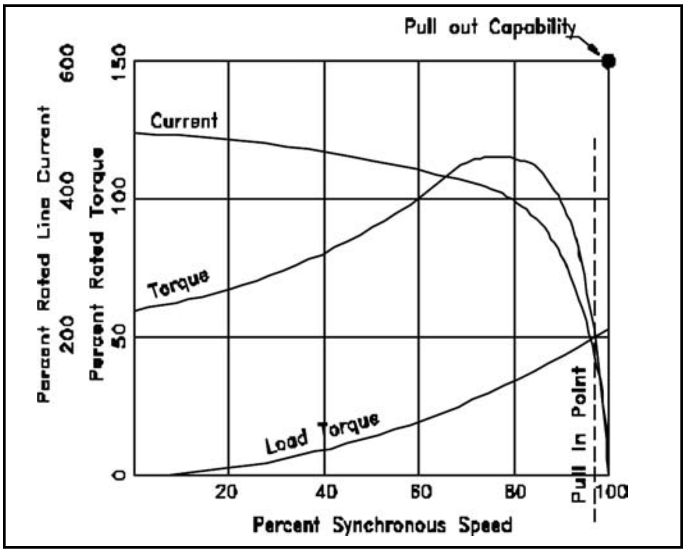


Figure 8

For example, consider a high inertia drive such as a fan. The torque required by the fan at nearly full speed is, say, 100 percent based on nameplate horsepower. Assume also, the usual motor does not develop sufficient synchronizing strength to synchronize this high WK2 at any less than 98 percent synchronous speed. Should a motor with torque capability of 100 percent at 95 percent synchronous speed be applied to the fan, the motor would fail to synchronize because it would not be able to develop the required 100 percent torque at 98 percent speed. (This typical speed torque curves of Figure 8 shows how motor torque capability drops as the motor nears synchronous speed.)

In summary, any guarantee of pull-in torque must be accompanied by the value of load WK2 on which the guarantee is based. Otherwise it has no meaning.

In addition to considering the effect of load WK2 on acceleration into synchronism at near full speed, the motor designer must also consider the acceleration from zero speed to the pull-in point. Higher load WK2 requires high-energy input and consequently high heat loss in the amortisseur winding.

To compensate for this, motors with high WK2 loads (five to fifty times normal) are built in larger frames to provide the accelerating capability. Also, as a consequence of high load WK2, acceleration time becomes considerably extended.

The pullout, or maximum torque (see Figure 8) of a synchronous motor is unlike the induction motor breakdown torque in that no speed change occurs until the motor pulls out of step, since the amount of torque that can be sustained depends upon the strength of the two locked HMFs and decrease in the strength of either will reduce the torque capability of the motor. Thus, a synchronous motor with a separate DC excitation source such as an M-G set or a shaft-driven exciter will have its pull-out torque vary directly with the voltage change.

If the excitation is of the static type which uses the AC supply as its power source, the excitation too, will decrease with line voltage drop. Since the pullout torque varies directly with field excitation, the total effect of line voltage variation on the pull-out torque will be to the square of the voltage change. It must be noted that 0.8 P.F. motors with their larger fields generally have more pullout torque than 1.0 P.F. motors of the same horsepower and speed.

In the selection of a synchronous motor for a specific application it is important to know the actual torque requirements. In most cases, the nominal torques tabulated in Figure 7 should not be specified. As was stated previously, the starting and pull-in torques should be no higher than necessary inasmuch as increased torques can only be had at the expense of an increase in starting current which shows up as a more or less major disturbance of system voltage. On the other hand, some applications require considerably more starting and pull-in torque than nominal; thus, a synchronous motor should be built to specific application.

LOADS AND OVERLOADS

In addition to specifying the horsepower rating, the frequency and severity of overloads, if any, should be described. When the motor load follows a duty cycle, care should be exercised in determining the horsepower rating of the motor. This is especially true because the rms motor heating is not a direct function of the rms horsepower.

This is because the field current is normally maintained at rated value and the stator current does not drop linearly with load. A typical example would show that although the load becomes essentially zero, the armature current drops from 100 percent rated load to about 80 percent. So, although the horsepower output is zero, the stator current is 80 percent of rated load and the corresponding copper loss is about 64 percent of what it is at rated load.

EXCITATION

The requirement for a source of excitation for the synchronous motor has, in some cases, been overlooked.

There are several excitation systems available including:

(1) direct-connected exciter;
(2) floor-mounted belted exciters;
(3) M-G set;
(4) static excitation; and
(5) brushless exciters.

The high-speed synchronous motor with end-shield mounted bearings generally has used a direct-connected exciter. This results in a compact unit with the exciter rotor passed on a short shaft extension on the end opposite drive. The exciter stator is rabbeted to the motor end shield. For pedestal bearing construction, the exciter is usually best mounted on its own foundation or base pad, rather than "overhung" from the pedestal. When the low-speed synchronous motor is equipped with a conventional DC exciter, the exciter is generally belt driven rather than direct coupled to the motor shaft to take advantage of its lower cost of the high speed DC machine. However, if the low-speed unit has a brushless exciter, the excitation unit's rotating element is mounted directly on the motor rotor. The exciter stationary element is mounted by brackets directly on the motor frame for a desirable compact unit.

Some installations use the M-G set (a high-speed induction motor driving a DC generator) which can be remotely mounted from the motor, and can, if desired serve more than one motor at a time. Low-speed units, and especially engine-type units used with compressors, have used this scheme.

Similar to the M-G set is the static exciter. This can be remotely mounted and converts AC to DC without rotating elements. It usually is mounted with the motor-starting equipment. This method of excitation is fast becoming the most commonly used.

The brushless exciter mentioned previously has the one outstanding feature of requiring no brushes in the DC circuit. The motor equipped with brushless excitation has therefore reduced maintenance costs since there are no brushes, collector rings, and exciter commutators. The brushless system is ideal for hazardous locations such as often are found with compressor applications, and has been successfully applied to low-speed pump drives where the reduced maintenance requirements are especially appealing.

SYNCHRONOUS MOTOR APPLICATIONS

Synchronous motors are used in practically all basic industries. The tabulation (Figure 9) is not complete, either as to the industries included or as to the applications within each industry, but it does suggest the larger number of uses for synchronous machines.

While the tabulation (Figure 9) would indicate that there are many "standard" applications, most synchronous motors should be tailored to their respective drives. True, a motor with standard torques will often "fill the bill", but in many cases torques lower than standard would be sufficient. In these instances, the motor should be specified for the lower requirements. Lower starting current may result which will produce less line disturbance during the starting cycle and this will result in lower mechanical stresses on the motor coils. It is always to the user's best interest to give complete information including the actual torques required when ordering synchronous motors.

Synchronous Motor Applications By Industry

Industry	*Application*
Water and Sewage Works	Pumping Stations
Pulp & Paper	Jordans, Refiners, Beaters, Defibrators, Vacuum and W Pumps, Compressors, Chippers, Grinders, Motor-Generator Sets
Lumber	Band Saws, Gang Saws, Pumps, Compressors
Textile	Pumps, Compressors, Motor-Generator Sets
Steel	Motor-Generator Sets, Rolling Mills, Ventilating Fans, Pumps, Compressors, Sintering Fans
Building	Pumps, Air Conditioning Compressors
Machinery	Hydraulic Press Pumps, Compressors
Rock Products	Ball Mills, Tube Mills, Crushers, Pumps, Compressors
Chemical	Pumps, Compressors
Rubber	Rubber Mills, Pumps, Compressors, Banbury Mixers, Plasticators
Power Plants	Blowers, Feed-Water and Cooling Water Pumps
Mining	Motor-Generator Sets for Shovels, Draglines and Mine Hoists, Pumps, Fans and Compressors

Figure 9

INTER-SYSTEM GROUND NOISE: CAUSE AND EFFECTS

American Power Conversion

INTRODUCTION

A UPS system is an essential part of a business computer system, but it cannot completely protect the computer from all power related problems. In working with installers of business computer systems over time, APC has identified installation configurations which have special risks. Most computer power protection equipment is designed to protect the load or loads, which are attached. In the ideal case, no connection point to the computer exists except for the AC power cord. This allows the power protection equipment complete control over noise or transient voltage events that could enter the computer from the outside world.

In the real world, computers are more often than not interconnected to other remote devices via network wiring, printer data lines, and modem telephone lines. AC power protection equipment cannot stop transients from entering the computer via these data connections. In fact, these connections may allow a dangerous and common type of AC power problem to damage hardware or stored data. The problem is INTER-SYSTEM GROUND NOISE and it cannot be corrected using typical AC-only power protection equipment.

SAFETY GROUNDING

All computer equipment is equipped with three wire grounding type AC power connectors. Many types of equipment, such as lamps, have only two wire-type plugs since two wires are all that is necessary to deliver AC power. The third wire is a safety ground wire, which is connected to all exposed exterior metal parts on the computer equipment. The grounding connection provided at the wall receptacle is connected within the building to copper water pipes and/or structural metal parts of the building. The purpose of this arrangement is to protect the user from electrical shock when the exposed metal parts of a faulty computer and building structural metal parts are touched. For safety, exposed devices such as RS-232 connectors and printer ports are considered to be exposed metal parts. For this reason, the voltage at any connector pin must be ground, or present a small voltage with respect to ground. The result is that in virtually all computer equipment, the CPU common wire or ground reference is connected to the safety grounding wire (and the enclosure) of the equipment.

In a system including equipment that is interconnected via data lines, the safety grounding arrangement leads to a conflict. Every interconnected device has two connections which are attempting to establish the common reference voltage for data communications: 1) the common wire in the data line, which connects the device to other equipment, and 2) the device's safety grounding wire. This situation is sometimes known as a "ground loop". In the next section it will be shown how the existence of this loop can lead to differences between the common reference voltage between any interconnected devices, which can be damaging to hardware and data. These ground voltage differences between interconnected devices must not be confused with other power problems such as common mode noise, normal mode noise, EMI, or RFI. These ground voltage differences are referred to as INTER-SYSTEM GROUND NOISE.

INTER-SYSTEM GROUND NOISE IS NOT THE SAME AS COMMON MODE NOISE

One of the most widespread misunderstandings in the field of computer power protection is the difference between inter-system ground noise and common mode noise. Common mode noise is defined as noise that exists between the power conductors, hot and neutral, with respect to the ground conductor. Inter-system ground noise exists between the ground wires supplying interconnected computers. Free standing computers which are not connected via any data lines cannot experience inter-system ground noise. It is possible for a computer to experience severe common mode noise, while experiencing no inter-system ground noise, and vice-versa. These two problems are completely independent.

A key reason why there is so much confusion in this area stems from the fact that power protection equipment can reduce common mode noise but cannot help correct inter-system ground noise.

SOURCES AND EFFECTS OF INTER-SYSTEM GROUND NOISE

A simplified diagram of an ideal interconnected system is shown in Figure 1. The grounding wires from all of the interconnected equipment come from the same source, ensuring that they start out having the same voltage. No current of any kind flows in any of the ground wires, and they are not subject to any magnetic fields. This ensures that there can be no voltage drop along the ground wires. The result is that all points along all of the ground wires are at the same voltage and that there is no inter-system ground noise between devices attached at various points along the grounding system. The oscillographs in the figure show no current noise.

Unfortunately, significant effects prevent realization of the preceding ideal scenario. In some cases, the deviation from the ideal can result in data corruption and even hardware damage. An interconnected system experiencing inter-system ground noise is shown in Figure 2. In the figure, interconnected systems are subject to different ground noise voltages, giving rise to ground noise current in the data line which connects the two systems. The offending ground noise in this case results from noise current injected into the ground system of one of the computers by "other equipment". Inter-system ground noise can result from a variety of different problems, which are explained as follows:

GROUND NOISE INJECTION: Although the safety ground wire is intended for grounding of the equipment enclosure, all computer equipment uses this wire for another purpose - to provide a reference point to filter out unwanted emissions of radio frequency interference from the computer equipment. Common and normal mode electrical noise on the power line is injected into the ground line by the filter present in the power supply of each computer and workstation. Improperly designed surge suppressors may contribute to this problem.

EFFECT: This injected noise current gives rise to a noise voltage between the common references of the interconnected equipment. Because the noise voltages usually become larger when the distance between the equipment is increased, data transmissions can become compromised in some situations.

GROUND FAULTS: If the interconnected devices are on different electrical circuits in the building and one of these circuits is shared by some other unrelated equipment, which has an insulation failure, then before the circuit breaker trips, a very large fault current will be injected into the safety ground

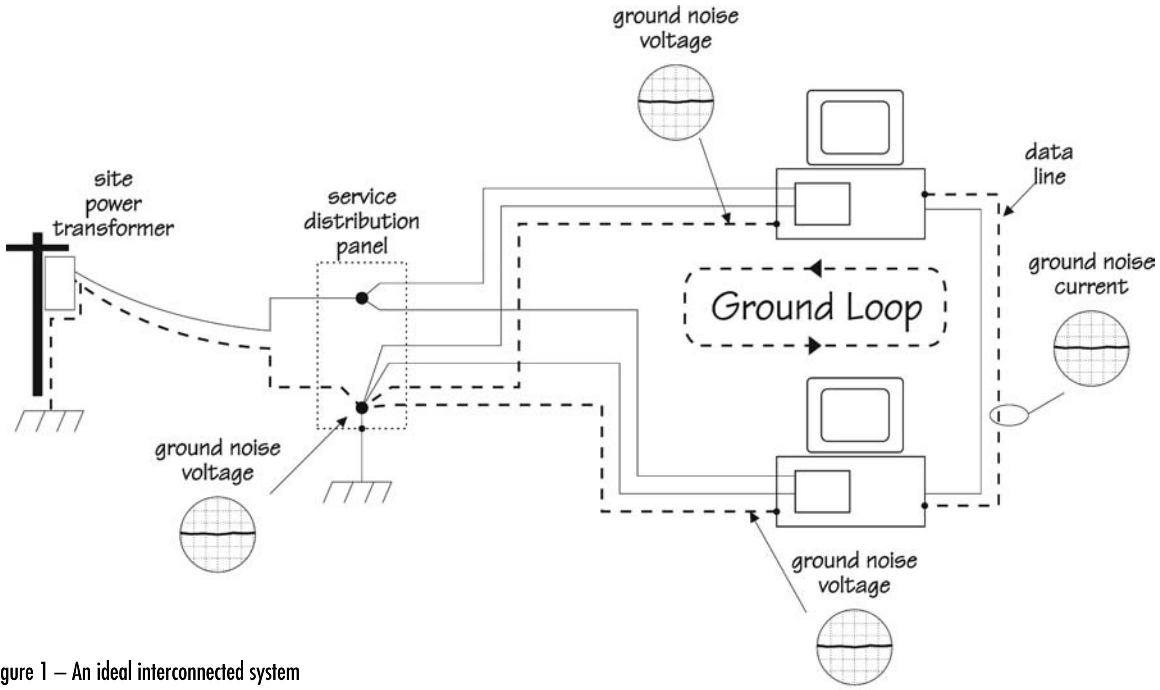


Figure 1 – An ideal interconnected system

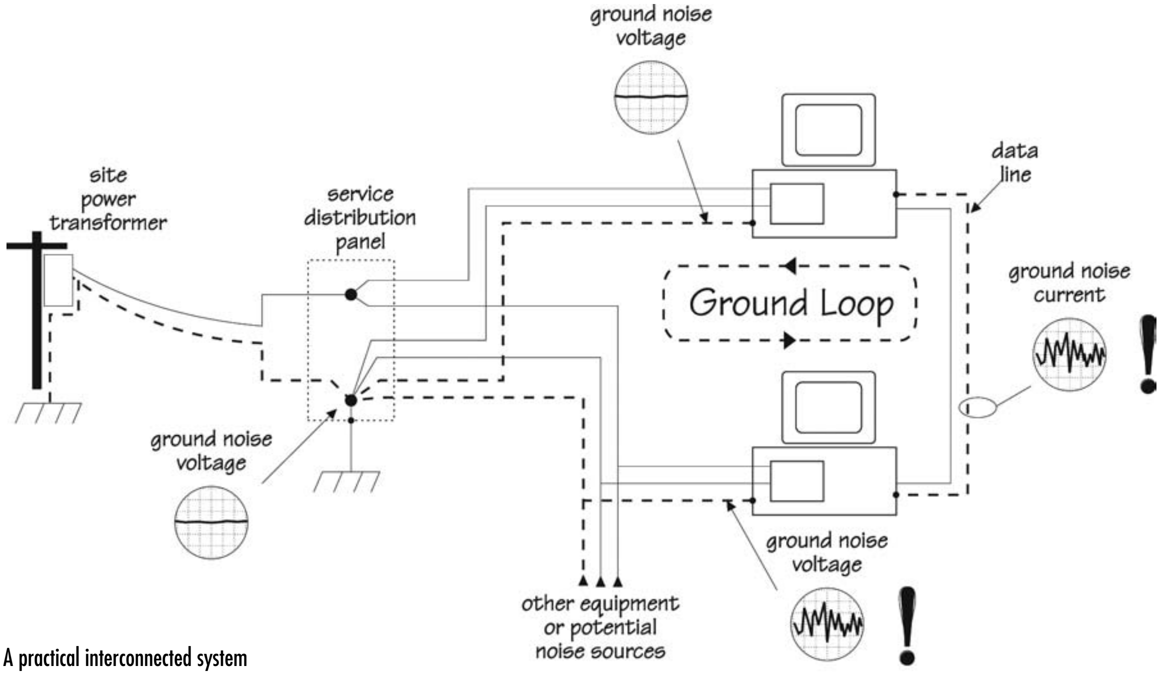


Figure 2 – A practical interconnected system

wire. This will give rise to a momentary ground voltage surge at the computer equipment that is supplied by the circuit breaker, which is tripping. The size of this voltage surge may be from a few Volts to over one-half of the rated power voltage (either 120VAC or 230VAC), depending on the quality of the grounding system.

EFFECT: This will result in a voltage difference between the common reference points of the interconnected equipment that can easily exceed the data signal safety voltage rating. Destruction of input/output drivers and CPU motherboards can result.

GROUND CURRENTS: This is the most common problem identified. If the pieces of interconnected equipment are supplied by different electrical sub-panels (circuit breaker boxes) in the same or different buildings, then many problems can cause the ground voltage supplied to the interconnected devices to be different. Depending on local or national electrical codes, many different wiring systems are possible between separate sub-panels. Most of these inter-panel wiring systems do not guarantee that the ground voltages supplied by the sub-panels will be equal. In many cases the inter-panel ground connections are themselves part of other ground loops (such as building frame members) unrelated to the ground loops caused by the device data connection. A large number of situations can give rise to dangerous ground voltage differences between sub-panels including nearby lightning strikes to ground, lightning induced currents in ground loops external to the ground loop caused by device data connections, poor building grounding (sandy soil), fault currents (breaker tripping) in apparently unrelated buildings or circuits, or nearby electrical repair work.

EFFECT: This will result in a voltage difference between the common reference points between devices, which can easily exceed the data cable safety voltage rating. Destruction of data interface drivers and CPU motherboards can result. Another common side effect is heating of the data cabling (cable becomes warm or hot to the touch).

LIGHTNING INDUCED VOLTAGES: This is a common and damaging form of ground voltage noise. In this case, the ground loop acts as an antenna. Nearby lightning strikes create enormous electromagnetic pulse noise, which is received by the antenna. A large circulating current in the ground loop can be created.

EFFECT: This current may cause the voltage difference between the common reference points on interconnected devices to exceed the safety voltage rating. Damage to the data interface driver cards is common, and propagation of the damage into the CPU motherboard is possible. The area of the ground loop controls the magnitude of the problem. In rare circumstances, other types of equipment may create electromagnetic pulses, which are picked up by the ground loop (such as NMR/MRI imaging machines).

BREAKING GROUND LOOPS BY CUTTING WIRES

It may be apparent that the source of all of these problems is the ground loop caused by the electrical safety ground. In many cases, disconnection of this ground at one piece of equipment may prevent problems.

However, ground wire disconnection should never be performed because it is illegal and presents a severe shock hazard. It is sometimes suggested that an isolation transformer might be used to solve the ground loop problem. This will not work because all safety agencies require that the ground wire of an isolation transformer be passed through between the input and output (only the power wiring may be isolated).

SOME EQUIPMENT IS RELATIVELY IMMUNE TO INTER-SYSTEM GROUND NOISE

Some network wiring is completely isolated and does not create ground loops when used to interconnect equipment. In this case, inter-system ground noise voltages can exist, but will have no effect. Examples of such immune network wiring are Ethernet and fiber-optic cables.

SOME EQUIPMENT IS VERY VULNERABLE TO INTER-SYSTEM GROUND NOISE

Examples of interconnections which are subject to inter-system ground noise are RS-232 data links, long printer data wiring, USB wiring, and network AUI wiring.

CONCLUSION

Inter-System Ground Noise is a type of power problem that is not widely understood but can result in misoperation or even destruction of equipment. The widespread use of Ethernet and optic fiber network connections, which are electrically isolated, has decreased the problem over time. However, non-isolated equipment connections such as RS-232, parallel, and USB can give rise to situations where Inter-System Ground noise poses a risk to equipment operation. Such connections should be kept short and the interconnected equipment should be powered from the same branch circuit.

TRACKING DOWN RANDOM TRIPS AND PROBLEMS

Fluke Corporation

The electrical loads in a modern factories, office buildings, schools and other buildings can challenge electrical equipment. In the old days most electrical loads were linear - either resistive or inductive - but today many of them create huge inrush currents or severe distortion on the AC waveform. Faced with these loads, switches may fail prematurely and motion sensors and ground fault circuit interrupters may trip for no apparent reason.

Hubbell Wiring Device-Kellems, a recognized industry leader with a well-deserved reputation for innovative and reliable products, will occasionally encounter an issue that defies explanation. That's when Steve Liscinsky gets called in.

Liscinsky is a project engineer with Hubbell, and it's his job to investigate such situations in the field. Liscinsky has become pretty good at tracking down issues - especially those related to unusual applications. And his favorite tracking tool is his Fluke 43B Power Quality Analyzer.

But he doesn't generally start investigating with the 43B; like a detective, he begins by questioning the witnesses - an electrician, a maintenance person, a consultant - and gathering all the information he can. What is the problem? When does it occur? What else is happening at the same time?

Once he's found out all he can by asking questions, he gets out his 43B and starts to take measurements, generally starting with voltage and everything to do with it: amplitude, frequency and harmonics. Then he looks at loads and currents, concentrating on the circuits with the Hubbell equipment. “We'll look at the hot,” he says; “we'll also look at the neutrals, too, especially in three-phase circuits, because that tells you a lot. That meter is particularly good for that; the resolution goes low enough that you can see if there's a problem or imbalance somewhere.”

Load-side measurements can be particularly revealing, “and one reason why I really like that meter,” says Liscinsky, “is because it does a nice job with measuring inrush currents.” Inrush currents can be sporadic, since they depend on the point on the incoming AC waveform at which a switch or relay contact closes. One measurement often isn't enough, “so we'll have to take many measurements. Statistically, we are comfortable taking about 30 measurements to get the peak,” says Liscinsky.

“It'll tell us if we've got much higher inrush currents than you'd normally see with just a few measurements, especially if there are some intermittent harmonic problems. That's where the meter works really nice.”

Once the cause of a problem has been found, “we have to recommend a solution, whether it be splitting the loads or derating whatever switchgear you've got in there because of the high inrush currents, high harmonics or whatever.”

Even when the application is found to be the cause of the issue, we will still take the information that we get and go back and review the performance of our product,” he explains. “Even though the products are perfectly good and they have gone through extensive UL testing for their respective ratings, we may still make design enhancements based on what we find out in the field to make an even better product.

“Sometimes a problem isn't actually caused by either the incoming AC power or an actual load attached to one of our devices.” Liscinsky tells of an incident in a plastic packaging plant. One particular Hubbell motion sensor was tripping for no apparent reason. “Normally, we would first try to rule out environmental conditions, and if they looked good, we would then check the line voltage for spikes by turning loads on and off, or by using the 43B's recording function, if necessary.”

So, Liscinsky put his 43B on the input power and started monitoring for voltage spikes.

There were spikes that coincided with the spurious tripping, but they did not appear to be large enough to cause a malfunction.

Liscinsky discovered that on the floor above, directly over the sensor, there was a machine that ultrasonically welded plastic packages shut. The floor was wood. Liscinsky asked the machine operator to whack the floor with a hammer whenever he activated the machine. Then he went back downstairs, “and sure enough I could see the little light on the motion sensor flickering when the machine was being activated.”

It turned out that the welding machine produced a big magnetic pulse, and that was enough to trip the sensor. “There was such high power,” he says, “you could see the spike it put on the power line, but you would not have thought that it should have caused the sensor to false trip. But the spike on the power line did clue us into the welding machine because of the timing of the spike versus the trip.”

Liscinsky also utilizes the 43B to demonstrate the situations to customers. When he finds a problem such as high inrush current, he can hand the 43B to the customer and show them what he has found. “The screen is large and easy to read. I can say to the customer, you hold this, and you read off the inrush current to me while I activate the load and take the numbers down,” he says. “So the customer can actually see the readings, and they can witness the issue just by looking at the screen.”

Liscinsky's advice for tracking down problems is to start by getting as much information as possible before going to the site. “Even if it ends up not being data you are not going to use, get as many clues as possible; that way when you go in to look at the application you have some kind of a logical plan of attack.”

Once on-site, try to get together as many people as needed. “You may want to have the original electrician who did the installations there,” he explains. “You have to find out who you need, as well as what you need.”

Then set out to find the source of the problem. Run through everything, even if it doesn't seem to be involved. “If I don't think the voltage is a problem, even if I think immediately it's a load problem, yet if I am at the panel, I'll still do all the measurements, because it really doesn't take too long.”

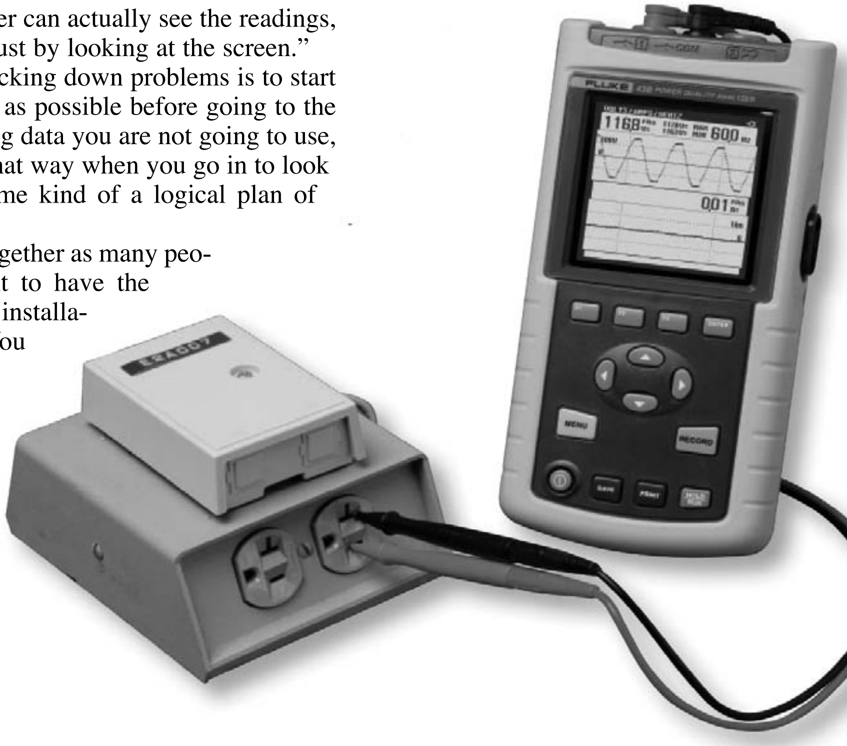
If measurements of voltage, current and wave shapes don't show anything in real time, especially with intermittent problems, then go to the record modes. “You can use them to record some suspected noise event. Your two choices, or the two steps are; try to initiate the power disturbance yourself by turning loads on and off, and if that doesn't reveal a problem, put the 43B in a longer record mode and wait for the power line disturbance.”

Experience also helps. “The customer will explain the problem, and when you go in there and you see the actual application, a little bell goes off in your head saying, “I've seen this before and this is what I'm going to do first. That can save some time checking certain things.”

He cites as an example the case of an extruding machine in a manufacturing plant. “They were using our ground-fault current interrupting devices and they would trip when a high power 480 V drive started up,” he says.

“Immediately we went to look at the input voltage waveform to the GFCIs, looking for distortion of the wave, and it was there, a huge amount of distortion.” In half an hour the problem was solved: “All we had to do was recommend the proper product for the application. This specific application required a device such as Hubbell's Industrial Grade GFCI which provides enhanced EMI filtering.” In other cases, adding an isolation transformer, a line filter or a capacitor in the right place might be what is needed to take care of a problem.

“The 43B meter is an excellent example of a product that does exactly what you expect of it. It is easy to use and has all of the features required to do a quick and thorough analysis.”



HOW STRAY VOLTAGE AFFECTS MULTIMETER MEASUREMENTS

Fluke Corporation

For most electrical measurements in the industrial environment, a high impedance digital multimeter or electrical tester is the appropriate tool. These test instruments have a relatively high-input impedance (>1 megohm), which means that when connected, they don't load the circuit under test. These test tools generally will not affect circuit operation or circuit measurements.

On the other hand, low impedance test instruments can seriously load down a circuit under test and, in some cases, can adversely affect circuit operation and circuit measurements. This can happen with sensitive control circuits or in many electronic circuits found within industrial machinery.

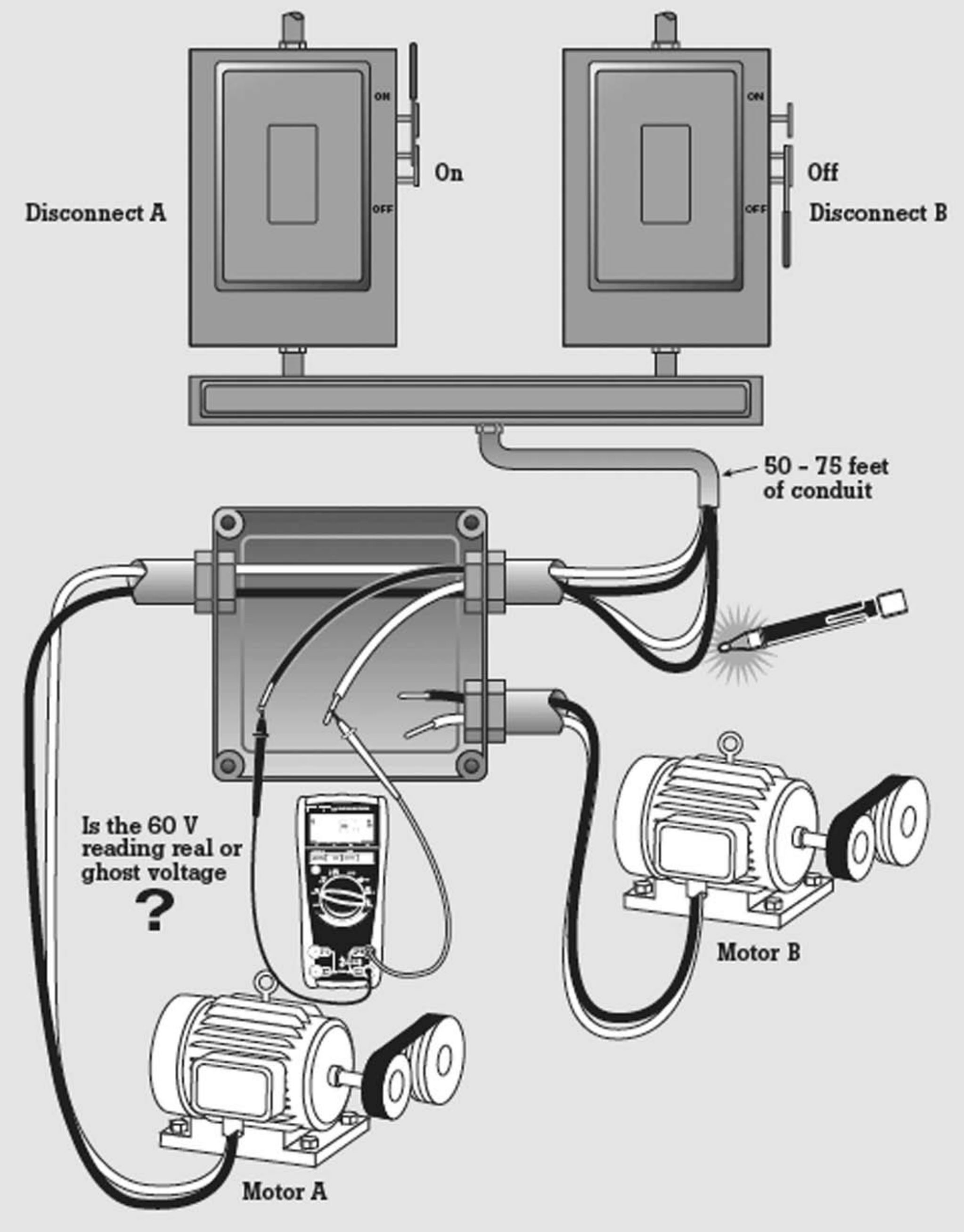
However, even with a high impedance multimeter, there's still one confusing measurement situation that can occur in facilities or manufacturing plants. It's called stray or ghost voltage, and it happens specifically when using a high impedance test instrument for day-to-day measurements.

Stray or ghost voltages occur from capacitive coupling between energized circuits and non-energized, non connected adjacent wiring. Because of this coupling effect and the multimeter's high impedance, it's not always possible to determine if the circuit under test is energized or de-energized, and this creates confusion for the person performing the test.

WHERE ARE STRAY VOLTAGES ENCOUNTERED?

The most common place to encounter stray voltage is in unused cable runs or electrical wiring in existing conduit. When facilities or buildings are built and wired, it's very common for electricians to pull extra wire through the conduit for future use.

These wires are typically left unconnected until needed, but are subject to capacitive coupling from the powered wires. Another example is an open ground or neutral on a 120 V branch circuit or in card cages where 120 volt control circuits are used to control assembly line or conveyor functions.



WHAT DOES STRAY VOLTAGE LOOK LIKE?

Generally, for most electrical measurements, a high impedance multimeter is the best tool, since you don't want the meter loading the circuit and affecting the circuit measurements. However, when dealing with capacitive coupling, a high impedance meter between ground or neutral to the unconnected cable or open connection will indicate some amount of voltage present. Typically this measured voltage reading may be as high as 50% of the energized voltage in the same proximity.

Is this voltage real? Yes, it is, but it's a static voltage, containing no real energy or current flow. When it comes to determining whether a circuit or connection is energized, this stray voltage reading presents a real source of confusion. Is the connection really hot or not?

THE FLUKE TL225 STRAY VOLTAGE ADAPTER TEST LEAD SET

The Fluke Stray Voltage Adapter Test Lead Set is an accessory that allows a high impedance multimeter to measure circuits, connections, cables or connectors subject to stray voltages. The adapter provides a low impedance load to the measured circuit, desensitizing the meter to low energy, spurious sources of interference. If the measurement points are energized with a hard voltage, the meter will simply display the voltage reading. If the measurement points contain a stray or ghost voltage, the meter will read very close to zero volts, indicating the circuit or connection is not energized.

WARNING

The stray voltage adapter is designed to be used in conjunction with high impedance digital multimeters for measurements on power circuits, to help determine whether the circuit is energized or not. The adapter presents a 3 k load to the circuit under test and thus will dissipate any stray voltage present if the circuit is not energized.

This adapter should not be used on low voltage control circuits or anywhere where the circuit under test could be adversely affected by this low impedance load. The adapter is designed to handle continuously applied power system voltages without damage, however proper use of this adapter is for intermittent use to determine whether a circuit is energized or not.

SAMPLE MEASUREMENT SCENARIO

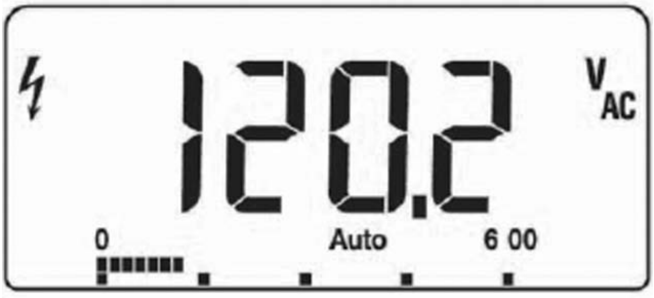


Figure A

Figure A is a normal reading for an energized 120 volt branch circuit between hot and neutral. This reading is displayed on the meter with or without using the stray voltage adapter.

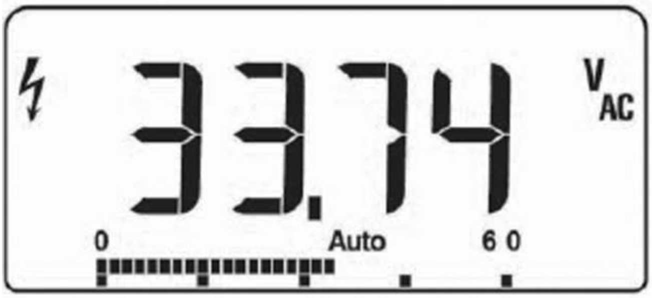


Figure B

Figure B is the measurement displayed with the high impedance DMM between neutral and an unconnected wire in the same conduit as a 120 volt branch circuit feed. Note the high impedance meter is displaying 33 volts. This is a capacitively coupled stray voltage reading.

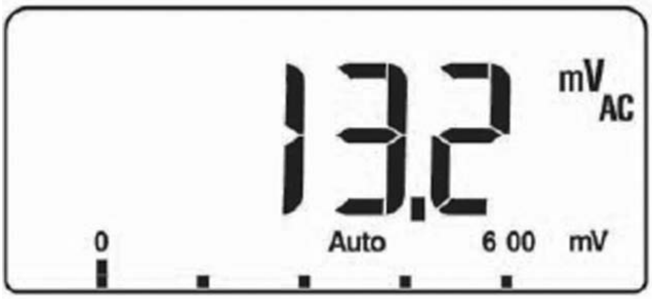


Figure C

Figure C is displaying the result of the measurement from Figure B when the stray voltage adapter is placed in the circuit. Note that the reading is now 13 millivolts or very close to zero volts, a non-energized connection.

The low impedance presented by the stray voltage adapter dissipates the stray voltage. If the reading in Figure B was a hard voltage, the reading in Figure C would have been the same reading as in Figure B.

SAFETY

Testing for stray voltage is a measurement typically made for a short period of time, such as less than a minute. The stray voltage eliminator module contained within the TL225 test lead kit is designed to withstand a continuous application of 1000 volts or less. The module has been tested to meet the IEC 1010-1 second edition CAT IV 600 V/CAT III 1000 V measurement category rating.

On a more personal safety note: If you've ever doubted your multimeter readings, consider the environment you're working in. Does it contain the ingredients for capacitive coupling? If it does, and if you need to rely on hot-or-not readings, you may want to consider adapting your multimeter. Stray voltage is confusing at best, and dangerous at worst. Don't be fooled!

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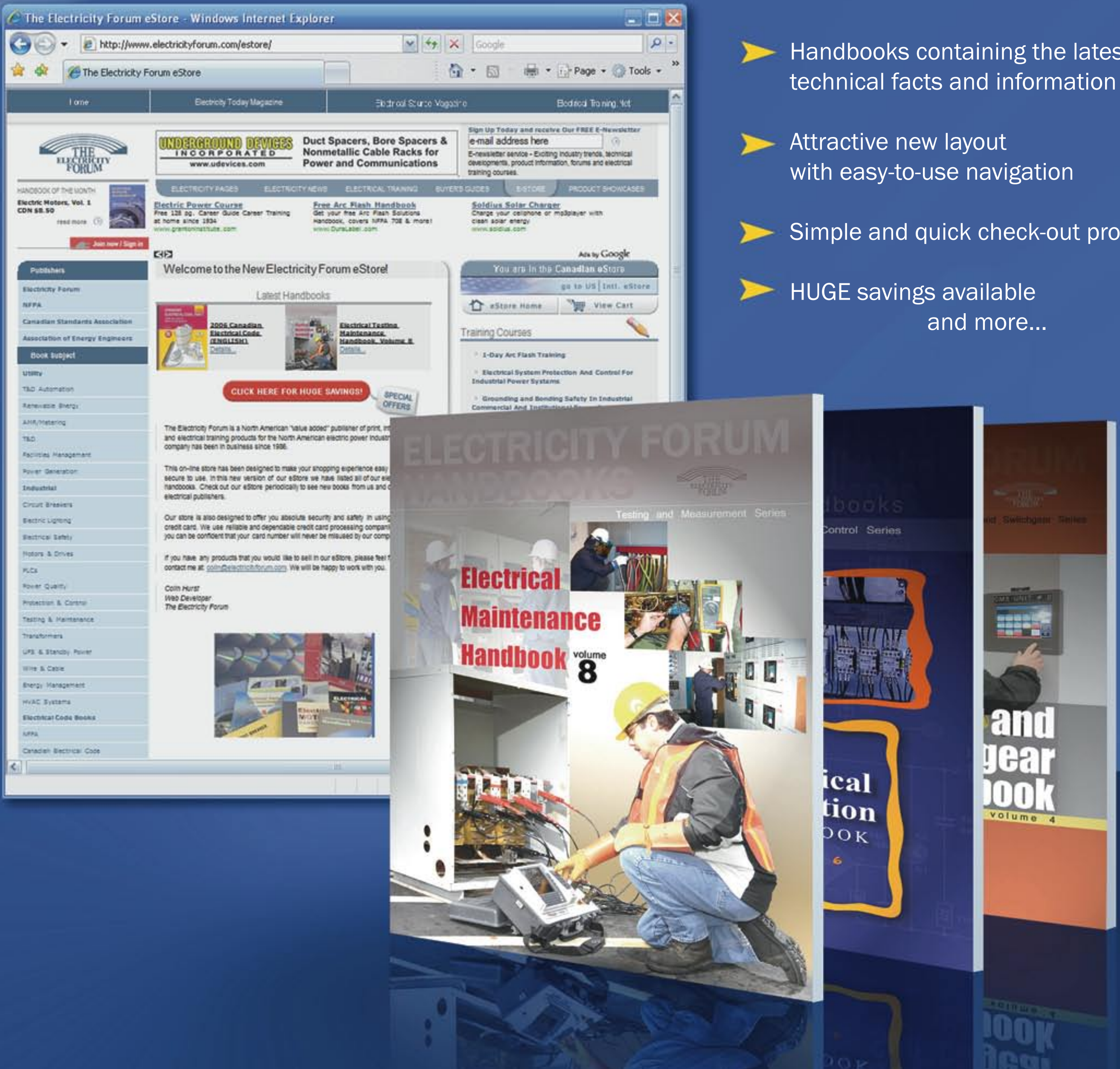

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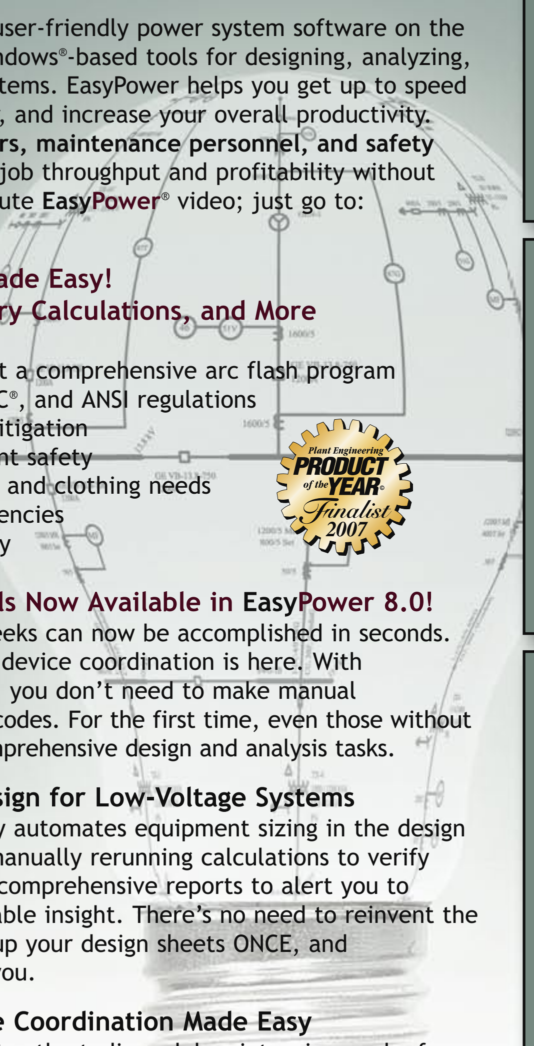

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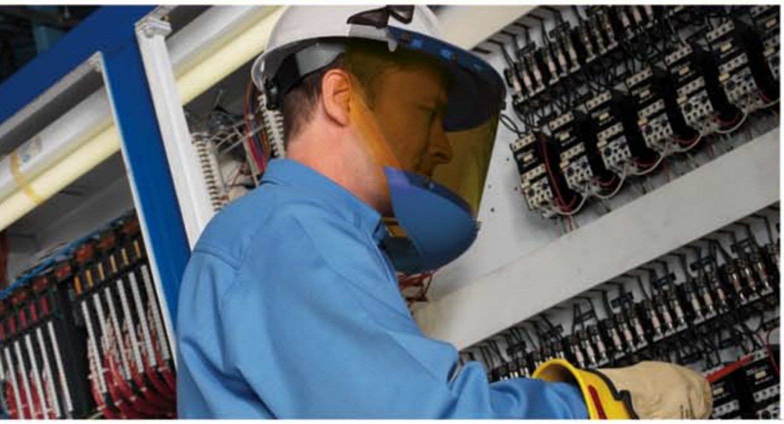
Are you compliant with Z462?

Canada's Workplace Electrical Standard



Non-FR 100% cotton after 480v disconnect arc flash.

Under provincial health and safety regulations employers have a general duty to keep their employees safe and take every precaution reasonable for the protection of workers.

Are you prepared? Equip your operation with a continuous, quality Flame Resistant Clothing (FRC) solution.

- **Dedicated Team** – Cintas has a team of specialists dedicated solely to protective apparel
- **Expertise and Knowledge** – As an industry leader, Cintas will keep you up-to-date on CSA Z462 and NFPA 70E PPE standards
- **Extensive Selection** – Cintas offers a wide selection of leading FRC fabrics, brands, and styles through rental, lease and purchase programs
- **Proper Cleaning** – Cintas cleans according to manufacturer specifications and industry regulations
- **Quality Repairs** – Cintas preserves protective properties by repairing with FR materials
- **Weekly Inspections** – Cintas ensures garments are continuously inspected to properly protect your employees
- **Inventory Services** – Cintas inventories your garments and delivers the right protection where and when you need it
- **Timely Add-ons** – New employees will be placed in uniform quickly

Contact us today for your FREE assessment.

1-800-CINTAS1 • www.cintas.ca/Z462

Design a FRC Uniform program that works for you.

Rent. Lease. Purchase.

NFPA® MEMBER

CINTAS® THE UNIFORM PEOPLE

www.cintas.ca